The Duke Power Annual Plan

November 1, 2005

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Duke Power, ("Duke Power" or "the Company"), a division of Duke Energy Corp., is responsible for meeting its customers' energy needs in a reliable, economical manner with a least-cost mix of generation resources and demand-reduction measures. For the past 10 to 15 years, the addition of low-cost peaking generation capacity was sufficient to meet incremental near-term needs. Now, however, Duke Power faces a potential need over the next decade for additional intermediate and baseload resources to meet the growing demand for electricity.

Based on preliminary analysis from last year, the Company issued a request for proposals (RFP) for peaking and intermediate capacity. Duke Power filed preliminary information with the North Carolina Utilities Commission (NCUC) pertaining to Certificates of Public Convenience and Necessity for up to 1600 MWs of new coal generation and 600 MWs of combined-cycle generation. In addition, the Company announced its intention to prepare a cost estimate for a combined construction and operating license for a new nuclear plant. The 2005 Annual Plan process focused on verifying and refining the results of the preliminary analysis to determine appropriate next steps.

Consistent with the responsibility to meet customer energy needs in a reliable, economical manner, the Company's resource planning approach includes both quantitative analysis and qualitative considerations. A quantitative analysis can provide insights on future risks and uncertainties associated with fuel prices, load growth rates, capital and operating costs and other variables; however it does not reflect state or national public policy trends or goals related to the energy industry. Additional perspectives such as the state of competitive markets, the importance of fuel diversity, the Company's environmental profile, the stage of technology deployment and regional economic development are also important factors to consider as long-term decisions are made regarding new generation.

Company management uses all of these perspectives and analysis to ensure that Duke Power will meet near-term and long-term load obligations, while maintaining future flexibility to adjust to changing operating circumstances.

Planning Process Results

The Fall 2005 Forecast indicates that Duke Power has sufficient resources to meet customer demand through the end of 2006. Beginning in 2007, approximately 330 MW of additional capacity will be needed to meet planning target reserve margins. The need grows to approximately 3400 MW by 2011 and 7400 MW by 2020. The factors that influence this are:

- Future load growth projections
- Reduction of available capacity and energy (resources), and
- A 17 percent target planning reserve margin over the 15 year horizon.

The quantitative analysis suggests that a combination of additional baseload, intermediate and peaking generation and demand-side management (DSM) programs are required over the next fifteen years. New coal and nuclear capacity additions, complemented by natural gas combustion turbine and combined-cycle units, are attractive supply-side options under a variety of sensitivities and scenarios. In light of this analysis, as well as the public policy debate on energy and environmental issues and the state of competitive markets, Duke Power has developed a strategy to ensure that the Company can reliably meet customers' energy needs while maintaining flexibility pertaining to long-term generation decisions.

The Company will take the following actions in the upcoming year:

- Complete the RFP process to evaluate potential peaking and intermediate generation opportunities in the wholesale market.
- Continue to evaluate new nuclear generation by pursuing the Nuclear Regulatory Commission's Combined Construction and Operating License, with the objective of potentially bringing a new plant on line by 2016.
- Continue to evaluate new coal generation, with the objective of potentially bringing additional capacity on line by 2011.
- Continue to evaluate coal and natural gas prices.
- Maintain the option to license and permit a new combined-cycle facility.
- Continue DSM program design and implementation.
- Complete an evaluation of renewable technologies.

I. INTRODUCTION

Duke Power has an obligation to provide reliable, economical electric service to its customers in North Carolina and South Carolina. To meet this obligation, the Company conducted a resource planning process that serves as the basis for its 2005 Annual Plan.

This 2005 Annual Plan will discuss:

- Duke Power's current state, including existing generation, demand and purchased power agreements
- The 15-year load forecast and resource need projection
- The target planning reserve margin
- New generation, demand-side and purchased-power opportunities
- The results of the planning process, and
- Near-term actions needed to meet customers' energy needs that maintains flexibility if operating environments change.

II. DUKE POWER CURRENT STATE

Overview

Duke Power is one of the largest investor-owned utilities in the United States, with an approximately 22,000-square-mile service area in central and western North Carolina and western South Carolina. In addition to retail sales to approximately 2.23 million customers, Duke Power also sells wholesale electricity to incorporated municipalities and to public and private utilities. The tables below show numbers of customers and sales of electricity by customer groupings.

Table 2.1
Retail Customers (1000s, by number billed)

	2004	**2003**	**2002**
Residential	1,841	1,814	1,782
General Service	306	300	293
Industrial	8	8	8
Nantahala Power & Light	67	66	64
Other	12	11	11
Total	2,234	2,199	2,158

(Number of customers is average of monthly figures)

Table 2.2
Electricity Sales (GWH Sold - Years Ended December 31)

Electric Operations	**2004**	**2003**	**2002**
Residential	24,542	23,356	23,898
General Service	24,775	23,933	23,831
Industrial	25,085	24,645	26,141
Nantahala Power & Light	1,995	1,898	1,787
Other[a]	267	268	269
Total Retail Sales	76,664	74,100	75,926
Wholesale Sales[b]	2,037	2,359	2,048
Total GWH sold	78,701	76,459	77,974

[a] Other = Municipal street lighting and traffic signals
[b] Wholesale sales include sales to Schedule 10A customers, Western Carolina University, City of Highlands and Catawba Owners. Short-term, non-firm wholesale sales subject to the BPM sharing agreement are not included.

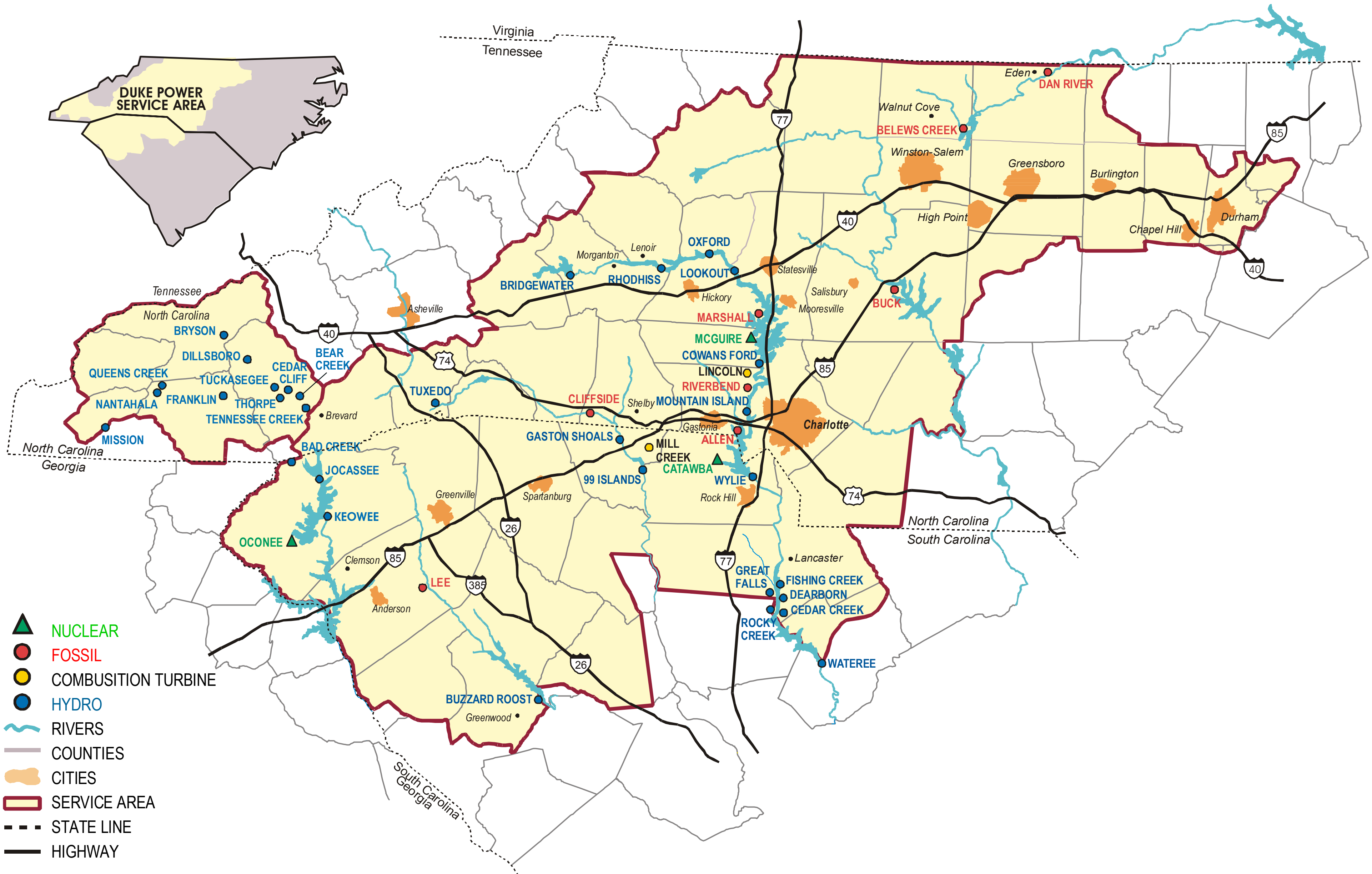
Duke Power meets energy demand in part by purchases from the open market, through longer-term purchased power contracts and from the following electric generation assets:

- Three nuclear generating stations with a combined net capacity of 6,996 MW (including all of Catawba Nuclear Station)
- Eight coal-fired stations with a combined capacity of 7,754 MW
- 31 hydroelectric stations (including two pumped-storage facilities) with a combined capacity of 3,169 MW, and
- Seven combustion turbine stations with a combined capacity of 2,447 MW.

Duke Power's power delivery system consists of approximately 94,000 miles of distribution lines and 13,000 miles of transmission lines. The transmission system is directly connected to all the utilities that surround the Duke Power service area. There are 22 interconnections with eight different utilities – Progress Energy Carolinas, American Electric Power, Tennessee Valley Authority, Southern Company, Yadkin, Southeastern Power Administration (SEPA), South Carolina Electric and Gas and Santee Cooper (also known as South Carolina Public Service Authority). These interconnections allow utilities to work together to provide an additional level of reliability. The strength of the system is also reinforced through coordination with other electric service providers in the Virginia-Carolinas (VACAR) subregion, Southeastern Electric Reliability Council (SERC) and North American Electric Reliability Council (NERC).

The following map provides a high-level view of the Duke Power system.

Duke Power Generating System



Transmission System Adequacy [1]

Duke Power monitors the adequacy and reliability of its transmission system and interconnections through internal analysis and participation in regional reliability groups. Internal transmission planning looks ahead 10 years at available generating resources and projected load to identify transmission system upgrade and expansion requirements. Corrective actions are planned and implemented in advance to ensure continued cost-effective and high-quality service. Regional reliability groups also use Duke Power's transmission model data in their analyses.

The Company monitors transmission system reliability by evaluating changes in load, generating capacity, transactions and topography. A detailed annual screening ensures compliance with Duke Power's Transmission Planning Guidelines for voltage and thermal loading, using screening methods that comply with SERC policy and NERC Reliability Standards. The screening results identify the need for future transmission system expansion and upgrades and are used as inputs into the Duke Power Transmission Asset Management Plan (TAMP). The TAMP process evaluates problem-solution alternatives and their priority, scope, cost, and timing. The result of the TAMP process is a budget and schedule of transmission system projects.

Duke Power evaluates all transmission reservation requests for impact on transfer capability and compliance with the Company's Transmission Planning Guidelines. Studies are performed to ensure transfer capability is acceptable and exceeds VACAR Reserve Sharing Agreement requirements. The VACAR Reserve Sharing Agreement ensures that all VACAR member control areas have sufficient generation to meet their largest single generation contingency. The TAMP process is also used to manage projects for improvement of transfer capability.

Lessons learned from the August 2003 blackout in the northeast United States have been incorporated into Duke Power's processes. Operators now have additional monitoring tools and training to enhance their ability to recognize deteriorating system conditions. Refined procedures have also been developed in the event a black start is required to restore the system.

SERC audits Duke Power every three years for compliance with NERC Reliability Standards. Specifically, the audit requires Duke Power to demonstrate that its

[1] NCUC Order dated February 22, 2005 in Docket No. E-100, Sub 102 requires utilities to address transmission system adequacy in annual plans and to provide FERC Form 715. Appendix C to this Annual Plan includes a copy of Duke Power's most recent FERC Form 715 with attachments and exhibits. Duke Power's FERC Form 715 is confidential pursuant to N.C. Gen. Stat. § 132-1.2, and Appendix C is filed under seal as specified in NCUC Rule R8-60.

transmission planning practices meet NERC standards and to provide data supporting the Company's annual compliance filing certifications.

Duke Power participates in a number of regional reliability groups to coordinate analysis of regional, sub-regional and inter-control area transfer capability and interconnection reliability. The reliability groups:

- Assess the interconnected system's capability to handle large firm and non-firm transactions
- Ensure that planned future transmission system improvements do not adversely affect neighboring systems, and
- Ensure the interconnected system's compliance with NERC Reliability Standards.

Regional reliability groups evaluate transfer capability and compliance with NERC Reliability Standards for the upcoming peak season and five and ten-year periods. The groups also perform computer simulation tests for high transfer levels to verify satisfactory transfer capability.

The Company serves as Reliability Coordinator for the VACAR sub-region. NERC conducted a readiness assessment of Duke Power's Reliability Coordinator function in June 2005 and found that VACAR has adequate facilities, processes and procedures to perform its Reliability Coordinator functions. NERC also determined that the staff is knowledgeable and competent, and identified several "Examples of Excellence" during the assessment.

Existing Generation Plants in Service

Duke Power's generation portfolio is a balanced mix of resources with different operating and fuel characteristics. This mix is designed to provide energy at the lowest reasonable cost to meet the Company's obligation to serve customers. Duke Power-owned generation, as well as purchased power, is evaluated on a real-time basis in order to select and dispatch the lowest-cost resources to meet system load requirements. In 2004, Duke Power's nuclear (45.9%) and coal-fired generating units (52.2%) met the vast majority of customer needs. Hydroelectric and combustion-turbine generation and economical purchases from the wholesale market supplied the remainder.

The tables below list the Duke Power plants in service in North Carolina and South Carolina with plant statistics, and the system's total generating capability.

Table 2.3
North Carolina [a,b,c,d]

NAME	UNITS	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Allen	1 – 5	1145.0	1179.0	Belmont, N.C.	Conventional Coal
Belews Creek	1 – 2	2270.0	2320.0	Belews Creek, N.C.	Conventional Coal
Buck	3 – 6	369.0	377.0	Salisbury, N.C.	Conventional Coal
Cliffside	1 – 5	760.0	770.0	Cliffside, N.C.	Conventional Coal
Dan River	1 – 3	276.0	283.0	Eden, N.C.	Conventional Coal
Marshall	1 – 4	2110.0	2110.0	Terrell, N.C.	Conventional Coal
Riverbend	4 – 7	454.0	464.0	Mt. Holly, N.C.	Conventional Coal
TOTAL N.C. CONVENTIONAL COAL		**7384.0 MW**	**7503.0 MW**		
Buck	7C–9C	93.0	93.0	Salisbury, N.C.	Combustion Turbine
Dan River	4C–6C	85.0	85.0	Eden, N.C.	Combustion Turbine
Lincoln	1 – 16	1268.0	1488.0	Stanley, N.C.	Combustion Turbine
Riverbend	8C–11C	120.0	120.0	Mt. Holly, N.C.	Combustion Turbine
TOTAL N.C. COMB. TURBINE		**1566.0 MW**	**1786.0 MW**		
McGuire	1 – 2	2200.0	2312.0	Huntersville, N.C.	Nuclear
TOTAL N.C. NUCLEAR		**2200.0 MW**	**2312.0 MW**		
N.C. Hydro Units		613.7 MW	613.7 MW	18 N.C. Hydro Stations	Hydro
TOTAL N.C. CAPABILITY		**11,763.7 MW**	**12,214.7 MW**		

Table 2.4
South Carolina [a,b,c,d]

NAME	UNIT #	SUMMER CAPACITY MW	WINTER CAPACITY MW	LOCATION	PLANT TYPE
Lee	1 – 3	370.0	372.0	Pelzer, S.C.	Conventional Coal
TOTAL S.C. CONVENTIONAL COAL		**370.0 MW**	**372.0 MW**		
Buzzard Roost	6C–15C	196.0	196.0	Chappels, S.C.	Combustion Turbine
Lee	4C–6C	90.0	90.0	Pelzer, S.C.	Combustion Turbine
Mill Creek	1 – 8	595.0	739.0	Blacksburg, S.C.	Combustion Turbine
TOTAL S.C. COMB TURBINE		**881.0 MW**	**1025.0 MW**		
Catawba	1 – 2	2258.0	2326.0	York, S.C.	Nuclear
Oconee	1 – 3	2538.0	2592.0	Seneca, S.C.	Nuclear
TOTAL S.C. NUCLEAR		**4796.0 MW**	**4918.0 MW**		
Jocassee	1 – 4	680.0	680.0	Salem, S.C.	Pumped Storage
Bad Creek	1 – 4	1360.0	1360.0	Salem, S.C.	Pumped Storage
TOTAL PUMPED STORAGE		**2040.0 MW**	**2040.0 MW**		
S.C. Hydro Units		515.2 MW	515.2 MW	11 S.C. Hydro Stations	Hydro
TOTAL S.C. CAPABILITY		**8602.2 MW**	**8870.2 MW**		

Table 2.5
Total Generation Capability [a,b,c,d]

NAME	SUMMER CAPACITY MW	WINTER CAPACITY MW
TOTAL DUKE GENERATING CAPABILITY	**20,366**	**21,085**

Note a: Unit information is provided by state, but resources are dispatched on a system-wide basis.

Note b: Summer and winter capability does not take into account reductions due to environmental emission controls.

Note c: Catawba Units 1 and 2 capacity reflects 100% of the station's capability, and does not factor in the North Carolina Municipal Power Agency #1's (NCMPA#1) decision to sell or utilize its 832 MW retained ownership in Catawba.

Note d: The Catawba units' multiple owners and their effective ownership percentages are:

CATAWBA OWNER	PERCENT OF OWNERSHIP
Duke Power	12.5%
North Carolina Electric Membership Corporation (NCEMC)	28.125%
NCMPA#1	37.5%
Piedmont Municipal Power Agency (PMPA)	12.5%
Saluda River (SR)	9.375%

Fuel Supply

Duke Power burns approximately 18 million tons of coal annually. Coal is procured primarily from Central Appalachian coal mines and delivered by Norfolk Southern or CSX railroads. The Company assesses coal market conditions to determine the appropriate mix of contract and spot purchases, in order to reduce the Company's exposure to the risk of price fluctuations. The Company may increase its diversity of coal supply as a result of the February 2005 RFP that will provide the ability to evaluate coal supply from throughout the United States and international sources.

To provide fuel for Duke Power's nuclear fleet, the Company maintains a diversified portfolio of natural uranium and downstream services (conversion, enrichment and fabrication) supply contracts from around the world. The majority of the energy production from Duke Power generating units has come from the coal and nuclear units (98%). Hence, the recent increases in natural gas and oil prices have had less impact on Duke Power's cost to produce energy than utilities who are more dependent upon oil and natural gas.

Renewable Energy Initiatives

Duke Power has supported development of renewable energy through:

- Financial and in-kind support of the North Carolina GreenPower program (a voluntary program that promotes the development of renewable generation resources)
- Development of a Small Customer Generator Rider, and
- Existing contracts with Qualifying Facilities.

The North Carolina GreenPower Program is a statewide initiative approved by the NCUC. The mission of NC GreenPower is to encourage renewable generation development from resources such as sun, wind, hydro and organic matter by enabling North Carolina electric consumers, businesses, and organizations to help offset the cost to produce green energy. Duke Power supports NC GreenPower by facilitating customer contributions to the program. The Company has also made direct financial contributions to the program.

Duke Power, other utilities and stakeholders worked collaboratively to develop Model Small Generator Interconnection Standards. These standards provide potential owners of small distributed generation systems, including renewable energy sources, with uniform, simplified standard criteria and procedures for interconnecting with electric utilities in North Carolina. Duke Power has filed with the NCUC, for approval, a Small Customer Generator Rider that incorporates this standardization.

Duke Power currently has purchased-power agreements with the following Qualifying Facility renewable energy providers:

- Salem Energy Systems, the Hanes Road Landfill in Winston-Salem - 3 MW
- Catawba County Blackburn Landfill facility - 3 MW
- Northbrook Carolina Hydro (5 facilities) - 6 MW
- Town of Lake Lure Hydro - 2 MW
- 19 hydro energy providers - 5 MW total *

* See Appendix K for further details on the 19 hydro energy providers.

Demand-Side Management (DSM) Programs

Duke Power uses DSM programs to help manage customer demand in an efficient, cost-effective manner. DSM programs can vary greatly in their dispatch characteristics, size and duration of load response, certainty of load response and frequency of customer participation. In general, DSM programs fall into two primary categories: energy efficiency and demand response (interruptible or time of use).

Demand Response – Load Control Curtailment Programs
These programs can be dispatched by the utility and have the highest level of certainty. Once a customer agrees to participate in a demand response load control curtailment program, the Company controls the timing, frequency and nature of the load response. Duke Power's load control curtailment programs include:

- Residential Air Conditioning Direct Load Control
- Residential Water Heating Direct Load Control.

Demand Response – Interruptible & Time of Use Programs
These programs rely either on the customer's ability to respond to a utility-initiated signal requesting curtailment or on rates with price signals that provide an economic incentive to reduce or shift load. Timing, frequency and nature of the load response depend on customers' voluntary actions. Duke Power's interruptible and time of use curtailment programs include:

- Programs using utility-requested curtailment signal
  - Interruptible Power Service
  - Standby Generator Control
- Rates using price signals
  - Residential Time-of-Use
  - General Service and Industrial Optional Time-of-Use rates
  - Hourly Pricing for Incremental Load and Hourly Pricing – Flex

Energy Efficiency Programs
These programs are typically non-dispatchable, conservation-oriented education or incentive programs. Energy and capacity savings are achieved by changing customer behavior or through the installation of more energy-efficient equipment or structures. All effects of these programs are reflected in the customer load forecast. Duke Power's existing energy efficiency programs include:

- Residential Energy Star
- Residential Service Controlled Water Heating
- Existing Residential Housing Program
- Special Needs Energy Products Loan Program

A more detailed description of each program can be found in Appendix D.

Curtailable Service

Duke Power offers a Curtailable Service Rider (Rider CS) to customers as a pilot program. This program mitigates the Company's financial risk of being forced, by capacity problems, to purchase power to supply native load during times of very high wholesale prices. Payments are closely aligned with market prices of energy, allowing the Company to offset high-cost energy purchases by paying participating customers to curtail load. This ultimately benefits all customers.

Wholesale Power Sales Commitments

Duke Power provides wholesale power sales to Western Carolina University (WCU), the city of Highlands and to customers served under Schedule 10A. These customers' load requirements are included in the Seasonal Projections of Load, Capacity and Reserves page 25. Under Interconnection Agreements, Duke Power is obligated to backstand the load of NCEMC and Saluda River, up to the amount of their ownership entitlement in

Catawba Nuclear Station. Those obligations are reflected throughout the 15-year planning horizon.

PMPA has served notice to end its Interconnection Agreements with Duke Power effective January 1, 2006. With that termination, the Company no longer has an obligation to supply supplemental energy to PMPA or to backstand PMPA's load up to its ownership entitlement in the Catawba Nuclear Station.

The Rural Utilities Service (RUS) has issued a Request for Bid for the purchase of Saluda River's ownership interest in the Catawba Nuclear Station. If the sale is completed, Duke Power's obligation to provide backstand for load up to Saluda's ownership entitlement would change.

Beginning January 1, 2005, two firm wholesale agreements became effective between Duke Power and NCMPA1. The first is a 75 MW capacity sale that expires 12/31/2007. The second is a backstand agreement of up to 432 MW (depending on operation of the Catawba and McGuire facilities) that expires 12/31/2007. These are reflected on line 19 of the Seasonal Projections of Load, Capacity and Reserves Table on page 25.

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

Wholesale Purchased-Power Agreements

Duke Power is an active participant in the wholesale market for capacity. The Company has issued RFPs for purchased-power capacity over the past several years, and has entered into purchased-power arrangements for over 2,000 MWs over the past 10 years. In addition, Duke Power has contracts with a number of Qualifying Facilities. The table below shows both the purchased power capacity obtained through RFPs as well as the larger Qualifying Facility agreements. See Appendix K for additional information on all purchases from Qualifying Facilities.

<u>Table 2.6</u>
Wholesale Purchased-Power Commitments

SUPPLIER	CITY	STATE	SUMMER FIRM CAPACITY (MW)	WINTER FIRM CAPACITY (MW)	CONTRACT START	CONTRACT EXPIRATION
Rowan County Power, LLC Unit 1	Salisbury	N.C.	152	185	6/1/02	5/31/07
Progress Ventures, Inc. Unit 1	Salisbury	N.C.	153	185	6/1/07	12/31/10
Rowan County Power, LLC Unit 2	Salisbury	N.C.	151	184	6/1/01	12/31/05
Progress Ventures, Inc. Unit 2	Salisbury	N.C.	153	184	1/1/06	12/31/10
Progress Ventures, Inc. Unit 3	Salisbury	N.C.	153	185	6/1/04	5/31/08
Progress Ventures, Inc. Unit 3	Salisbury	N.C.	153	185	6/1/08	12/31/10
Rockingham Power, LLC	Wentworth	N.C.	160	160	1/1/06	12/31/10
Cherokee County Cogeneration Partners, L.P.	Gaffney	S.C.	88	95	7/1/96	6/30/13
Catawba County	Newton	N.C.	3	3	8/23/99	8/22/14
Salem Energy Systems, LLC	Winston-Salem	N.C.	3	3	7/10/96	7/10/11
Ecusta Business Development Center	Brevard	N.C.	3	3	4/15/2004	4/14/2009
Northbrook Carolina Hydro, LLC	Various	Both	6	6	12/4/96	12/4/06
Town of Lake Lure	Lake Lure	N.C.	2	2	2/18/99	2/17/06
Misc. Small Hydro	Various	Both	5	5	Various	Assumed Evergreen

Summary of Wholesale Purchased Power Commitments
(as of January 1, 2006)

	WINTER 05/06	SUMMER 06
Total Non-Utility Generation	831 MW	726 MW
Duke Power allocation of SEPA capacity	19 MW	19 MW
Total Firm Purchases	850 MW	745 MW

Legislative and Regulatory Issues

Duke Power is subject to the jurisdiction of many federal agencies, including FERC and EPA, as well as state commissions and agencies. The Company can also be affected by public policy actions that states and the federal government may take. For example, Duke Power is currently implementing the North Carolina Clean Smokestacks Act to reduce sulfur dioxide (SO_2) and nitrogen oxide (NOx) emissions from its generation facilities, and will also have to comply with the newly issued federal rules (Clean Air Interstate Rule and Clean Air Mercury Rule) to reduce SO_2, NOx and mercury emissions.

In addition, policy debate has increased on the issue of global climate change at both the state and federal levels. There is a significant amount of uncertainty regarding future federal climate change policy, and meanwhile a patchwork of state approaches is emerging. These issues, as well as the development of competitive markets and other regulatory matters, (See Appendix N for further discussion) could have an impact on new generation decisions.

III. RESOURCE NEEDS ASSESSMENT (FUTURE STATE)

To meet the future needs of our customers, it is necessary to understand the load and resource balance. For each year of the planning horizon, Duke Power develops a load forecast of energy sales and peak demand. To determine total resources needed, the Company considers the load obligation plus a 17 percent target planning reserve margin. The capability of existing resources, including generating units, demand-side management programs and purchased-power contracts, are measured against the total resource need. Any deficit in future years will be met by a mix of additional resources that reliably and cost-effectively meet the load obligation.

The following sections provide detail on the load forecast and the changes to existing resources.

Load Forecast

The Fall 2005 Forecast includes projections for meeting the energy needs of new and existing customers in Duke Power's service territory. Certain wholesale customers have the option of obtaining all or a portion of their future energy needs from other suppliers. While this may reduce Duke Power's obligation to serve those customers, Duke Power assumes for planning purposes that its existing wholesale customer load (excluding Catawba owner loads as discussed below) will remain part of the load obligation.

The forecasts for 2005 through 2020 include the energy needs of the following customer classes:

- Duke Power retail
- Nantahala Power & Light (NP&L) retail
- Duke Power wholesale customers under Schedule 10A
- NP&L wholesale customers Western Carolina University and the Town of Highlands
- NCEMC load relating to ownership of Catawba

In addition, the forecast includes:

- Load equating to the portion of Catawba ownership related to PMPA and the Saluda River Electric Cooperative Inc. (SR), as well as PMPA's supplemental requirements above its ownership in 2005
- **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Notes (c), (e) and (f) on pages 20 - 21 give additional detail on how the four Catawba Joint Owners were considered in the forecasts.

The current 15-year forecast reflects a 1.8 percent average annual growth in summer peak demand, while winter peaks are forecasted to grow at an average annual rate of 0.8 percent. The forecast for average annual territorial energy need is 1.7 percent. The growth rates use 2005 as the base year with a 17,497 MW summer peak, a 16,315 MW winter peak and a 93,099 GWH average annual territorial energy need.

Duke Power retail sales have grown at an average annual rate of 1.8 percent from 1989 to 2004. (Retail sales, including line losses, are approximately 86 percent of the total energy considered in the 2005 Annual Plan.) This 15-year period of history reflects 10 years of strong load growth from 1989 to 1999 followed by five years of very little growth from 1999 to 2004. The following table shows historical and projected major customer class growth rates.

Table 3.1
Retail Load Growth

Time Period	Total Retail	Residential	General Service	Industrial Textile	Industrial Non-Textile
1989 to 2004	1.8%	2.5%	3.8%	-3.1%	1.4%
1989 to 1999	2.4%	2.4%	4.2%	-0.2%	2.5%
1999 to 2004	0.5%	2.8%	2.9%	-8.6%	-0.7%
2004 to 2015	1.6%	1.8%	2.8%	-4.6%	1.2%

A decline in the Industrial Textile class was the key contributor to the low load growth from 1999 to 2004, offset by growth in the Residential class over the same period. From 1999 to 2004, an average of almost 50,000 new residential customers per year was added to the Duke Power service area.

Duke Power's total retail load growth over the planning horizon is driven by the expected growth in Residential and General Service classes. Sales to the Industrial Textile class are expected to decline, but not as much as in the last five years. The Industrial Non-Textile class is expected to show positive growth, particularly in the Automobile, Rubber and Plastics, Instruments and Chemicals industries. (Additional details on the current forecast can be found in the Fall 2005 Forecast Book.)

The load forecast for the 2005 Annual Plan is the following:

Table 3.2
Load Forecast

YEAR[a,b,c,d,e,f]	SUMMER (MW)[g]	WINTER (MW)[g]	TERRITORIAL ENERGY (GWH)[g]
2006	17,376	15,425	92,333
2007	17,918	15,815	94,865
2008	18,236	15,934	96,348
2009	18,343	15,878	95,789
2010	18,635	16,001	97,479
2011	19,689	16,936	102,556
2012	20,026	17,119	104,388
2013	20,393	17,301	106,208
2014	20,727	17,497	107,973
2015	21,062	17,602	109,745
2016	21,413	17,758	111,662
2017	21,771	17,957	113,629
2018	22,140	18,116	115,625
2019	22,505	18,273	117,636
2020	22,870	18,381	119,707

Note a: The MW (demand) forecasts above are the same as those shown on page 29 of the Fall 2005 Forecast Book, but the peak forecasts vary from those shown on pages 24-27 of the Forecast Book, primarily because Fall 2005 Forecast Book's peak forecasts include the total resource needs for all Catawba Joint Owners and do not include the total resource needs of NP&L.

Note b: The impact of energy efficiency DSM programs is accounted for in the load forecast.

Note c: As part of the joint ownership arrangement for Catawba Nuclear Station, NCEMC and SR took sole responsibility for their supplemental load requirements beginning January 1, 2001. As a result, SR's supplemental load requirements above its ownership interest in Catawba are not reflected in the forecast. Beginning in 2009, the SR ownership portion of Catawba will not be reflected in the forecast due to a future sale of this interest, which will cause SR to become a full-requirements customers of another utility. SR has indicated that it will exercise the three-year notice to terminate the Interconnection Agreement (which includes provisions for reserves) this fall, which would result in termination at the end of September, 2008.

Note d: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Note e: As part of the joint ownership arrangement for the Catawba Nuclear Station, the NCMPA1 took sole responsibility for its supplemental load requirements beginning January 1, 2001. As a result, NCMPA1 supplemental load requirements above its ownership interest in Catawba Nuclear Station are not reflected in the forecast. In 2002, NCMPA1 entered into a firm-capacity sale beginning January 1, 2003, when it sold 400 MW of its ownership interest in Catawba. In 2003, NCMPA1 entered into another agreement beginning January 2004, when it chose not to buy reserves for its remaining ownership interest (432 MW) from Duke Power. These changes reduce the Duke Power load forecast by the forecasted NCMPA1 load in the control area (988 MW at 2005 summer peak) and the available capacity to meet the load obligation by its Catawba ownership (832 MW). The Plan assumes that the reductions remain over the 15-year planning horizon.

Note f: The PMPA has given notice that it will be solely responsible for its supplemental load requirements beginning January 1, 2006. Therefore, PMPA supplemental load requirements above its ownership interest in Catawba Nuclear Station are not reflected in the load forecast beginning in 2006. Neither will the PMPA ownership interest in Catawba be included in the load forecast beginning in 2006, because PMPA provided notice to terminate its existing Interconnection Agreement with Duke Power effective January 1, 2006. Therefore, Duke Power will not be responsible for providing reserves for the PMPA ownership interest in Catawba after that date. These changes reduce the Duke Power load forecast by the forecasted PMPA load in the control area (456 MW at 2005 summer peak) and the available capacity to meet the load obligation by its Catawba ownership (277 MW). The Plan assumes that the reductions remain over the 15-year planning horizon.

Note g: Summer peak demand, winter peak demand and territorial energy are for the calendar years indicated. (The customer classes are described at the beginning of this section.) Territorial energy includes losses and unbilled sales (adjustments made to create calendar billed sales from billing period sales).

Changes to Existing Resources

Duke Power will adjust the capabilities of its resource mix over the 15-year planning horizon. Retirements of generating units, system capacity uprates and derates, purchased-power contract expiration, and adjustments in DSM capability affect the amount of resources Duke Power will have to meet its load obligation. Below are the known or anticipated changes and their impacts on the resource mix.

Purchased-Power Contract Expirations

Duke Power has secured various purchased-power contracts with power marketers Progress Ventures Inc. and Rockingham Power that are currently in effect or will begin over the next three years. In 2006, the overall capability of the purchased-power contracts is approximately 618 MW. The capability in megawatts varies depending on the contract start times, their duration and capability of each contract. All contracts will expire by Dec. 31, 2010. For details, see Table 2.6, Wholesale Purchased Power Commitments, on page 16 Duke Power is currently conducting an RFP process to evaluate new intermediate and peaking resource options available beginning in 2007.

Generating Units Projected To Be Retired

Various factors have an impact on decisions to retire existing generating units. These factors, including the investment requirements necessary to support ongoing operation of generation facilities, are continuously evaluated as future resource needs are considered. The following table reflects current assessments of generating units with identified decision dates for retirement or major refurbishment. The conditions of the units are evaluated annually and decision dates are revised as appropriate.

<u>Table 3.3</u>
Projected Unit Retirements

STATION	CAPACITY IN MW	LOCATION	DECISION DATE	PLANT TYPE
Buzzard Roost Hydro[a]	7	Chappels, S.C.	6/30/2006	Conventional Hydro
Buzzard Roost 6C	22	Chappels, S.C.	6/30/2008	Combustion Turbine
Buzzard Roost 7C	22	Chappels, S.C.	6/30/2008	Combustion Turbine
Buzzard Roost 8C	22	Chappels, S.C.	6/30/2008	Combustion Turbine
Buzzard Roost 9C	22	Chappels, S.C.	6/30/2008	Combustion Turbine
Buzzard Roost 10C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 11C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 12C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 13C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 14C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Buzzard Roost 15C	18	Chappels, S.C.	6/30/2010	Combustion Turbine
Riverbend 8C	30	Mt. Holly, N.C.	12/31/2010	Combustion Turbine
Riverbend 9C	30	Mt. Holly, N.C.	12/31/2010	Combustion Turbine
Riverbend 10C	30	Mt. Holly, N.C.	12/31/2010	Combustion Turbine
Riverbend 11C	30	Mt. Holly, N.C.	12/31/2010	Combustion Turbine
Buck 7C	31	Spencer, N.C.	12/31/2010	Combustion Turbine
Buck 8C	31	Spencer, N.C.	12/31/2010	Combustion Turbine
Buck 9C	31	Spencer, N.C.	12/31/2010	Combustion Turbine
Dan River 4C	30	Eden, N.C.	12/31/2010	Combustion Turbine
Dan River 5C	30	Eden, N.C.	12/31/2010	Combustion Turbine
Dan River 6C	25	Eden, N.C.	12/31/2010	Combustion Turbine

Note a: Duke Power has an operating lease for the Buzzard Roost Hydro Unit which expires June 30, 2006.

Reserve Margin Explanation and Justification

Considering customer demand uncertainty, unit outages and weather extremes, reserve margins are necessary to help ensure the availability of adequate resources. Many factors have an impact on the appropriate levels of reserves, including existing generation performance, lead times needed to acquire or develop new resources, and product availability in the purchased-power market.

Duke Power's experience has shown that a 17 percent target planning reserve margin is sufficient to provide reliable power supplies, based on the prevailing expectations of reasonable lead times for the development of new generation, siting of transmission facilities and procurement of purchased capacity. As part of the Company's process for determining its target planning reserve margins, Duke Power reviews whether the current target planning reserve margin was adequate in the prior period. From September 2003 through September 2005, generating reserves, defined as available Duke Power generation plus the net of firm purchases less sales, never dropped below 500 MW. Since 1997, Duke Power has had sufficient reserves to reliably meet customer load with limited need for activation of interruptible programs. The DSM Activation History in Appendix D illustrates Duke Power's limited activation of interruptible programs through the end of September 2005.

Duke Power also continually reviews its generating system capability, level of potential DSM activations, scheduled maintenance, environmental retrofit equipment and environmental compliance requirements, purchased power availability and transmission capability to assess its capability to reliably meet customer demand. The Company will continue to monitor lead times for permitting and construction of new generation and transmission facilities, to procure power in the purchased-power market and to assess its power supply planning process (reserve margins) for possible changes.

While Duke Power uses a 17% target planning reserve margin for long-term planning, it also assesses its reserve margins on a short-term basis to determine whether to pursue additional capacity in the short-term power market. As each peak demand season approaches, the Company has a greater level of certainty regarding the customer load forecast and total system capability, due to greater knowledge of near-term weather conditions and generation unit availability.

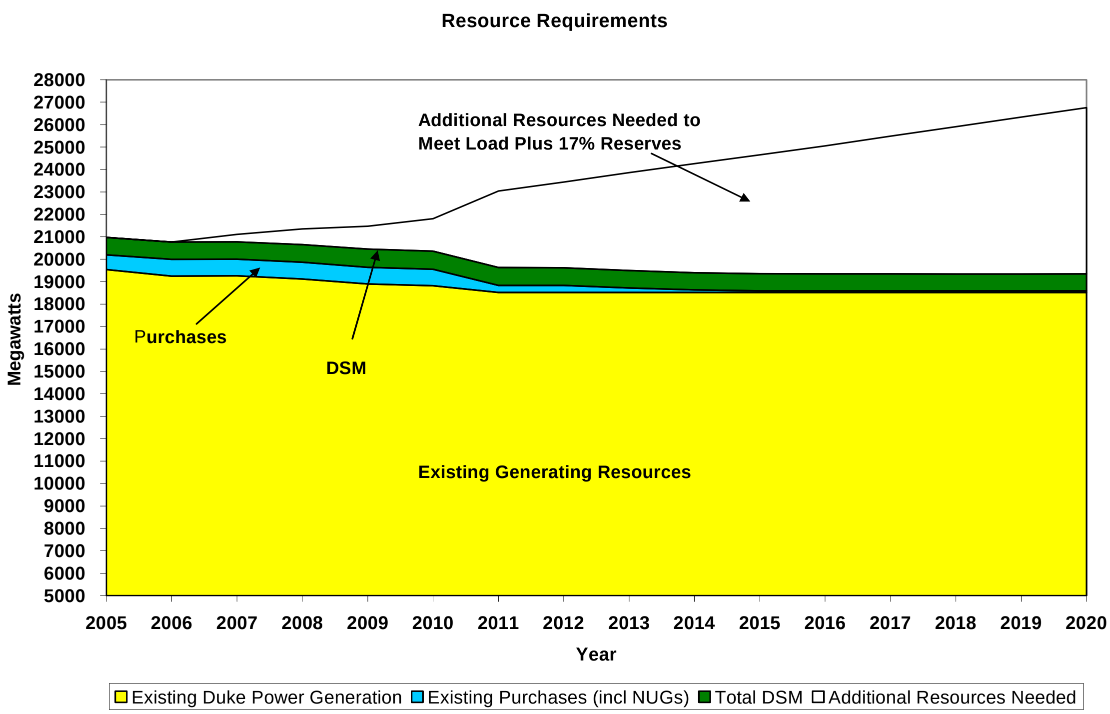
Duke Power uses adjusted system capacity[2], along with Interruptible DSM capability to satisfy Duke Power's NERC Reliability Standards requirements for operating and contingency reserves. Contingencies include events such as higher than expected unavailability of generating units and increased customer load due to extreme weather conditions.

[2] Adjusted system capacity is calculated by adding the expected capacity of each generating unit plus firm purchased-power capacity, less firm wholesale capacity sales.

Load & Resource Balance

The following chart shows the existing resources and resource requirements to meet the load obligation, plus the 17 percent target planning reserve margin. Beginning in 2005, existing resources, consisting of existing generation, DSM, and purchased power to meet load requirements, total 20,976 MW. The load obligation plus the 17 percent target planning reserve margin is 20,587 MW, indicating sufficient resources to meet Duke Power's obligation through 2006. A need for approximately 330 MW of additional capacity begins in 2007 and grows over time due to load growth, unit capacity adjustments, unit retirements, DSM reductions and expirations of purchased-power contracts. The need grows to approximately 3,400 MW by 2011 and 7,420 MW by 2020.

Chart 3.1
Load & Resource Balance



Projected Cumulative Future Resource Additions

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Resource Need	330	680	1010	1440	3400	3810	4360	4850	5290	5700	6130	6570	7000	7420

The following table contains the Seasonal Projections of Load Capacity and Reserves for Duke Power where the Cumulative Future Resource Additions reflects the megawatts needed to reach a 17% percent reserve margin.

Seasonal Projections of Load, Capacity, and Reserves

W = WINTER, S = SUMMER	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W
	05/06	2006	06/07	2007	07/08	2008	08/09	2009	09/10	2010	10/11	2011	11/12	2012	12/13
Forecast															
1 Duke System Peak	15,425	17,376	15,815	17,918	15,934	18,236	15,878	18,343	16,001	18,635	16,936	19,689	17,119	20,026	17,301
Cumulative System Capacity															
2 Generating Capacity	19,976	19,257	19,967	19,236	19,979	19,235	19,627	18,908	19,616	18,924	19,535	18,518	19,237	18,518	19,237
3 Capacity Additions	0	2	0	50	0	0	0	0	50	0	0	0	0	0	0
4 Capacity Derates	0	0	(12)	(26)	(25)	(25)	0	(11)	(23)	0	0	0	0	0	0
5 Capacity Retirements	0	(7)	0	0	0	(88)	0	0	0	(108)	(298)	0	0	0	0
6 Cumulative Generating Capacity	19,976	19,252	19,955	19,260	19,954	19,122	19,627	18,897	19,643	18,816	19,237	18,518	19,237	18,518	19,237
7 Cumulative Purchase Contracts	850	745	842	740	842	740	842	740	839	737	326	319	323	316	212
8 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Cumulative Future Resource Additions	0	0	0	330	330	680	680	1,010	1,010	1,440	1,440	3,400	3,400	3,810	3,810
10 Cumulative Production Capacity	20,826	19,997	20,797	20,330	21,126	20,542	21,149	20,647	21,492	20,993	21,003	22,237	22,960	22,644	23,259
Reserves w/o DSM															
11 Generating Reserves	5,401	2,621	4,982	2,412	5,192	2,306	5,271	2,304	5,491	2,358	4,067	2,548	5,841	2,618	5,958
12 % Reserve Margin	35.0%	15.1%	31.5%	13.5%	32.6%	12.6%	33.2%	12.6%	34.3%	12.7%	24.0%	12.9%	34.1%	13.1%	34.4%
13 % Capacity Margin	25.9%	13.1%	24.0%	11.9%	24.6%	11.2%	24.9%	11.2%	25.6%	11.2%	19.4%	11.5%	25.4%	11.6%	25.6%
DSM															
14 Cumulative DSM Capacity	395	766	387	776	392	792	401	821	417	808	411	794	405	780	397
Existing DSM Capacity	395	766	387	751	380	737	374	721	367	708	361	694	355	680	347
Potential New DSM Capacity	0	0	0	25	12	55	27	100	50	100	50	100	50	100	50
15 Cumulative Equivalent Capacity	21,221	20,763	21,184	21,106	21,518	21,334	21,550	21,468	21,909	21,801	21,414	23,031	23,365	23,424	23,656
Reserves w/DSM															
16 Equivalent Reserves	5,796	3,387	5,369	3,188	5,584	3,098	5,672	3,125	5,908	3,166	4,478	3,342	6,246	3,398	6,355
17 % Reserve Margin	37.6%	19.5%	34.0%	17.8%	35.0%	17.0%	35.7%	17.0%	36.9%	17.0%	26.4%	17.0%	36.5%	17.0%	36.7%
18 % Capacity Margin	27.3%	16.3%	25.3%	15.1%	26.0%	14.5%	26.3%	14.6%	27.0%	14.5%	20.9%	14.5%	26.7%	14.5%	26.9%
Sales (BPM)															
19 Equivalent Sales	127	127	127	127											
Equivalent Reserves	5663	3254	5236	3055	5584	3098	5672	3125	5908	3166	4478	3342	6246	3398	6355
% Reserve Margin	36.5%	18.6%	33.0%	17.0%	35.0%	17.0%	35.7%	17.0%	36.9%	17.0%	26.4%	17.0%	36.5%	17.0%	36.7%
% Capacity Margin	26.7%	15.7%	24.7%	14.5%	26.0%	14.5%	26.3%	14.6%	27.0%	14.5%	20.9%	14.5%	26.7%	14.5%	26.9%

Seasonal Projections of Load, Capacity, and Reserves

W = WINTER, S = SUMMER	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	2013	13/14	2014	14/15	2015	15/16	2016	16/17	2017	17/18	2018	18/19	2019	19/20	2020
Forecast															
1 Duke System Peak	20,393	17,497	20,727	17,602	21,062	17,758	21,413	17,957	21,771	18,116	22,140	18,273	22,505	18,381	22,870
Cumulative System Capacity															
2 Generating Capacity	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518
3 Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Capacity Derates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Cumulative Generating Capacity	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518
7 Cumulative Purchase Contracts	205	117	117	72	72	72	72	72	72	72	72	72	72	72	72
8 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Cumulative Future Resource Additions	4,360	4,360	4,850	4,850	5,290	5,290	5,700	5,700	6,130	6,130	6,570	6,570	7,000	7,000	7,420
10 Cumulative Production Capacity	23,083	23,714	23,485	24,159	23,880	24,599	24,290	25,009	24,720	25,439	25,160	25,879	25,590	26,309	26,010
Reserves w/o DSM															
11 Generating Reserves	2,690	6,217	2,758	6,557	2,818	6,841	2,877	7,052	2,949	7,323	3,020	7,606	3,085	7,928	3,140
12 % Reserve Margin	13.2%	35.5%	13.3%	37.3%	13.4%	38.5%	13.4%	39.3%	13.5%	40.4%	13.6%	41.6%	13.7%	43.1%	13.7%
13 % Capacity Margin	11.7%	26.2%	11.7%	27.1%	11.8%	27.8%	11.8%	28.2%	11.9%	28.8%	12.0%	29.4%	12.1%	30.1%	12.1%
DSM															
14 Cumulative DSM Capacity	768	398	763	399	759	399	755	400	752	400	747	402	749	404	751
Existing DSM Capacity	668	348	663	349	659	349	655	350	652	350	647	352	649	354	651
Potential New DSM Capacity	100	50	100	50	100	50	100	50	100	50	100	50	100	50	100
15 Cumulative Equivalent Capacity	23,851	24,112	24,248	24,558	24,639	24,998	25,045	25,409	25,472	25,839	25,907	26,281	26,339	26,713	26,761
Reserves w/DSM															
16 Equivalent Reserves	3,458	6,615	3,521	6,956	3,577	7,240	3,632	7,452	3,701	7,723	3,767	8,008	3,834	8,332	3,891
17 % Reserve Margin	17.0%	37.8%	17.0%	39.5%	17.0%	40.8%	17.0%	41.5%	17.0%	42.6%	17.0%	43.8%	17.0%	45.3%	17.0%
18 % Capacity Margin	14.5%	27.4%	14.5%	28.3%	14.5%	29.0%	14.5%	29.3%	14.5%	29.9%	14.5%	30.5%	14.6%	31.2%	14.5%
Sales (BPM)															
19 Equivalent Sales															
Equivalent Reserves	3458	6615	3521	6956	3577	7240	3632	7452	3701	7723	3767	8008	3834	8332	3891
% Reserve Margin	17.0%	37.8%	17.0%	39.5%	17.0%	40.8%	17.0%	41.5%	17.0%	42.6%	17.0%	43.8%	17.0%	45.3%	17.0%
% Capacity Margin	14.5%	27.4%	14.5%	28.3%	14.5%	29.0%	14.5%	29.3%	14.5%	29.9%	14.5%	30.5%	14.6%	31.2%	14.5%

ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLE

The following notes are numbered to match the line numbers on the SEASONAL PROJECTIONS OF LOAD, CAPACITY, AND RESERVES table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Power August 3, 1998.

2. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 103 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale to Southern Energy Company.
   Also, on January 1, 2006, Generating Capacity reflects a 277 MW reduction to account for PMPA termination of their interconnection agreement with Duke Power.
   Because the Lee CTs serve as a redundant safe-shutdown facility for Oconee Nuclear Station and are required by the NRC for operation of Oconee, the retirement of the existing CTs at Lee in 2006 will coincide with the addition of new CTs at Lee also in 2006 of 86 MW.

3. Capacity Additions reflect an estimated 2 MW Marshall unit double flow IP rotor upgrade and 100 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency from the new runners.

4. The expected Capacity Derates reflect the impact of parasitic loads from planned scrubber additions to various Duke fossil generating units. The units, in order of time sequence on the LCR table is Marshall 1 - 4, Belews Creek 1 & 2, Allen 1 - 3, Cliffside 5, and Allen 4 & 5.

5. The 120 MW capacity retirement in 2010 represents the projected retirement date for all CTs at Riverbend.
   The 88 MW capacity retirement in 2008 represents the projected retirement date for 4 CT's at Buzzard Roost(Wst).
   The 93 MW capacity retirement in 2010 represents the projected retirement date for the existing CTs at Buck.
   The 108 MW capacity retirement in 2010 represents the projected retirement date for 6 CT's at Buzzard Roost(GE).
   The 85 MW capacity retirement in 2010 represents the projected retirement date for CTs at Dan River.
   Duke has an operating lease for the 7 MW Buzzard Roost Hydro Unit which expires 6/30/2006.
   On May 23, 2000, the NRC issued to Duke a renewed facility operating license for its three nuclear units at Oconee. Duke now has the option to operate its Oconee units for up to 20 years following the year 2013. Duke will evaluate on an ongoing basis the viability of operating past the year 2013. With respect to planning purposes, the Oconee capacity is still in the plan.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

7. Cumulative Purchase Contracts have several components:

   A. Effective January 1, 2001, the SEPA allocation was reduced to 94 MW. This reflects self scheduling by Seneca, Greenwood, Saluda River, NCEMC, and NCMPA1. The 94 MW reflects allocations for PMPA and Schedule 10A customers who continue to be served by Duke.
   B. Piedmont Municipal Power Agency has given notice that it will be solely responsible for total load requirements beginning January 1, 2006. This reduces the SEPA allocation to 18 MW in 2006, which is attributed to Schedule 10A customers who continue to be served by Duke.
   C. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 22 MW.
   D. Purchase of 151 MW from Rowan County Power, LLC, Unit 2 began June 1, 2001 and expires December 31, 2005.
   E. Purchase of 152 MW from Rowan County Power, LLC, Unit 1 began June 1, 2002 and expires May 31, 2007.
   F. Purchase of 153 MW from Rowan County Power, LLC, Unit 3 began June 1, 2004 and expires May 31, 2008.
   G. Purchase of 153 MW from Progress Ventures, Inc. Rowan Unit 2 begins January 1, 2006 and expires December 31, 2010.
   H. Purchase of 153 MW from Progress Ventures, Inc. Rowan Unit 1 begins June 1, 2007 and expires December 31, 2010.
   I. Purchase of 153 MW from Progress Ventures, Inc. Rowan Unit 3 begins June 1, 2008 and expires December 31, 2010.
   J. Purchase of 160 MW from Dynegy/Rockingham unit begins January 1, 2006 and expires December 31, 2010.

9. Cumulative Future Resource Needs represent a combination of new capacity resources , short/long-term capacity purchases from the wholesale market, capacity purchase options, or capability increases which are being considered.
   Neither the date of operation, the type of resource, nor the size is firm. All Future Resource Needs are uncommitted and represent capacity required to maintain the target planning reserve margin.

12. Reserve margin is shown for reference only.
    Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

13. Capacity margin is the industry standard term. A 14.6 percent capacity margin is equivalent to a 17.0 percent reserve margin.
    Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

14. Cumulative Demand Side Management capacity represents the demand-side management contribution toward meeting the load. The programs reflected in these numbers include interruptible Demand Side Management programs designed to be activated during capacity problem situations.

IV. RESOURCE ALTERNATIVES TO MEET FUTURE ENERGY NEEDS

Many potential resource options are available to meet future energy needs. They range from expanding existing DSM programs to developing new DSM programs to adding new generation capacity to the Duke Power system.

Following are the generation (supply-side) technologies Duke Power considered in detail throughout the planning analysis:

Conventional Technologies (technologies in common use)

- 564 MW Combustion Turbine (CT)
- 585 MW Combined-Cycle (CC), with and without duct firing
- 400 MW Supercritical Conventional Fossil
- 600 MW Supercritical Conventional Fossil
- 800 MW Supercritical Conventional Fossil
- 1,200 MW Supercritical Conventional Fossil
- 1,600 MW Supercritical Conventional Fossil

Demonstrated Technologies (technologies with limited acceptance and not in widespread use)

- 2,234 MW Nuclear AP1000
- 600 MW Integrated Gasification Combined Cycle (IGCC)

Below are the DSM programs that were considered throughout the planning process:

Demand Response Programs

- Direct Load Control
- Interruptible Service
- Standby Generation

See Appendix J for a discussion of resources evaluated and the process used to screen the supply-side options to reach the list above.

V. OVERALL PLANNING PROCESS CONCLUSIONS

Duke Power's Resource Planning process provides a framework for the Company to assess, analyze and implement a cost-effective approach to reliably meet customers' growing energy needs. In addition to assessing qualitative factors such as fuel diversity and wholesale market structure, a quantitative assessment was conducted using a simulation model. A variety of sensitivities and scenarios were tested against a base set of inputs, allowing the Company to better understand how potentially different future operating environments such as fuel commodity price changes, environmental emission mandates and structural regulatory requirements can affect resource choices and ultimately the cost of electricity to customers. (Appendix A provides a detailed description and results of the quantitative analysis).

The quantitative analysis suggests that a combination of additional baseload, intermediate and peaking generation and demand-side management (DSM) programs are required over the next fifteen years to reliably meet customer demand. The generation resource mix consists of natural gas combustion turbine and combined-cycle units as well as coal and nuclear capacity. In nearly all the sensitivities and scenarios tested, the plan featuring 1,600 MW of new coal capacity and 2,200 MW of new nuclear capacity performed best on a present value of revenue requirements basis.

In light of the quantitative results, as well as consideration of qualitative issues such as the public policy debate on energy and environmental issues and the state of competitive markets, Duke Power has developed a strategy to ensure that the Company can reliably meet customers' energy needs while maintaining flexibility pertaining to long-term generation decisions. The Company will take the following actions in the upcoming year:

- Complete the RFP process to evaluate potential peaking and intermediate generation opportunities in the wholesale market.
- Continue to evaluate new nuclear generation by pursuing the Nuclear Regulatory Commission's Combined Construction and Operating License, with the objective of potentially bringing a new plant on line by 2016.
- Continue to evaluate new coal generation, with the objective of potentially bringing new capacity on line by 2011.
- Complete the RFP process to evaluate potential peaking and intermediate generation opportunities in the wholesale market.
- Continue to evaluate coal and natural gas prices.
- Maintain the option to license and permit a new combined-cycle facility.
- Continue DSM program design and implementation.
- Complete an evaluation of renewable technologies.

APPENDICES

APPENDIX A: QUANTITATIVE ANALYSIS

This appendix provides an overview of the quantitative analysis of resource options available to meet customers' future energy needs.

Overview of Analytical Process

Assess Resource Needs

Duke Power estimates the required load and generation resource balance needed to meet future customer demands by assessing:

- Customer load forecast peak and energy – identifying future customer aggregate demands to identify system peak demands and developing the corresponding energy load shape
- Existing supply-side resources – summarizing each existing generation resource's operating characteristics including unit capability, potential operational constraints and life expectancy
- Existing demand-side resources – detailing demand-side resource program characteristics including customer participation levels, demand reduction potential and reliability
- Operating parameters – determining operational requirements including target planning reserve margins and other regulatory considerations.

Identify and Screen Resource Options for Further Consideration

Options reflect a diverse mix of technologies and fuel sources (gas, coal, nuclear and renewable) as well as near-term and long-term timing and availability. Supply-side and demand-side options are screened based on the following attributes:

- Technically feasible and commercially available in the marketplace
- Compliant with all federal and state requirements
- Long-run reliability
- Reasonable cost parameters.

Demand-side management options should also cover multiple customer segments including residential, commercial and industrial.

Develop Theoretical Portfolio Configurations

This step begins with a nominal set of varied inputs to test the system under different market conditions. These analyses yield many different theoretical configurations of the total operating (production) and capital costs required to meet an annual 17 percent target planning reserve margin while minimizing the long-run revenue requirements to customers.

The nominal set of inputs includes:

- Fuel costs and availability for coal, gas, and nuclear generation
- Development, operation and maintenance costs of both new and existing generation
- Compliance with current environmental regulations
- Cost of capital
- System operational needs for load ramping, voltage/VAR support, spinning reserve (10 to 15-minute start-up) and other requirements as a result of VACAR / North American Electric Reliability Council (NERC) agreements
- The projected load and generation resource need, and
- A menu of new supply-side and demand-side options with corresponding costs and timing parameters.

Duke Power reviewed a number of variations to the theoretical portfolios to aid in the development of the portfolio options in the following section.

Develop Various Portfolio Options

Using the insights gleaned from developing theoretical portfolios, Duke Power creates a representative range of generation plans reflecting plant designs, lead times and environmental emissions limits.

Recognizing that different generation plans expose customers to different sources and levels of risk, a variety of portfolios is developed to assess the impact of various risk factors on the costs to serve customers. For example, in considering the possibility of a new nuclear plant, the permitting process may delay or even prevent its development. Therefore, in addition to the nominal input of a nuclear availability date, additional test portfolios assume a delay in nuclear plant availability as well as no availability at all.

Conduct Portfolio Analysis

Portfolio options are tested under the nominal set of inputs as well as a variety of risk sensitivities and scenarios, in order to understand the strengths and weaknesses of various resource configurations and evaluate the long-term costs to customers under various potential outcomes.

The following sensitivities are evaluated:

- Construction cost sensitivity
  - High costs to construct a new coal plant
  - High costs to construct a new nuclear plant
- Load forecast variations
  - Increase relative to base forecast
  - Decrease relative to base forecast
- Fuel price variability
  - High coal prices
  - Low coal prices
  - High natural gas prices
  - Low natural gas prices

- Constant higher natural gas and coal prices
- Constant lower natural gas and coal prices
- Carbon tax[3]

In addition to the above sensitivities, the following scenarios are evaluated to understand the inter-relationship of multiple assumptions changing concurrently:

- Constant higher natural gas and coal prices AND higher new coal construction costs
- Constant higher natural gas and coal prices AND higher new nuclear construction costs
- Carbon tax AND lower load than base forecast

Quantitative Analysis Results

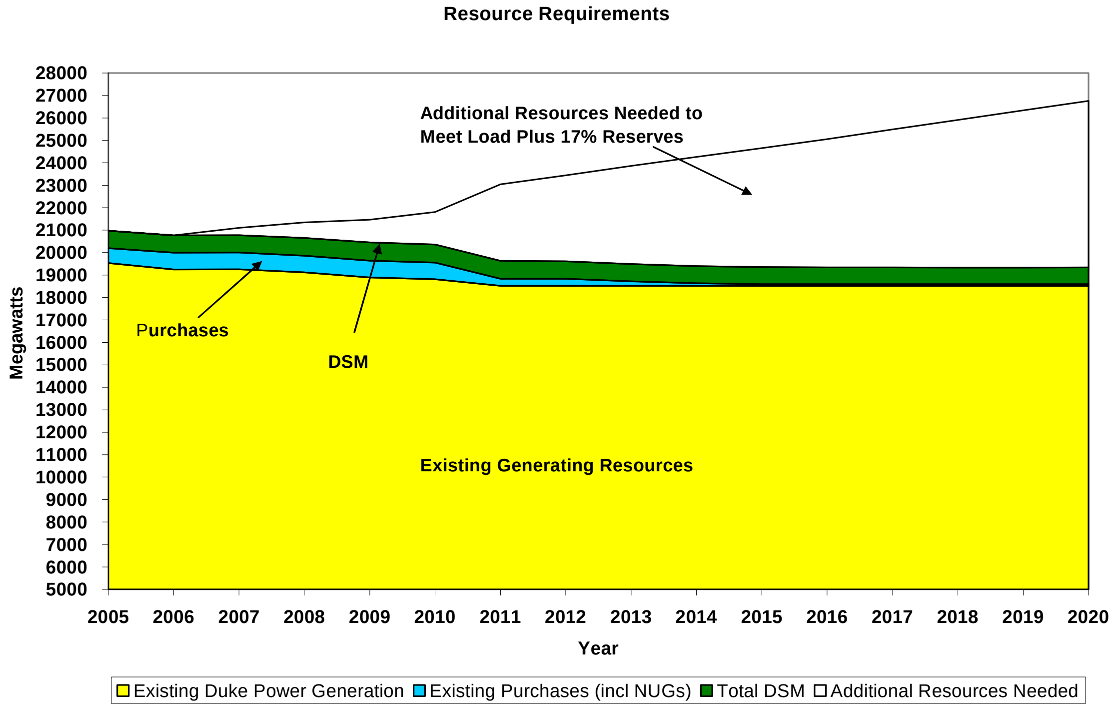
Resource Needs

Customer load growth coupled with the expiration of purchased-power contracts results in significant resource needs to meet energy and peak demands, based on the following assumptions:

- 1.8% average summer peak system demand growth over the next 15 years
- Generation reductions of more than 600 MW due to purchased-power contract expirations by 2011
- Generation retirements of approximately 500 MW of old fleet combustion turbines by 2011
- Approximately 122 MW of net generation reductions due to new environmental equipment
- Continued operational reliability of existing generation portfolio
- Continued operational reliability of the existing DSM interruptible capacity (750 MW)
- Using a 17 percent target planning reserve margin for the planning horizon

The chart below represents existing resources, load growth and future resource needs.

[3] Despite significant uncertainty surrounding potential future climate change policy, Duke Power has incorporated climate change policy sensitivity in its resource planning process. Inclusion of this sensitivity is not intended to reflect Duke Power's or Duke Energy's expectation regarding future climate change policy.



Projected Cumulative Future Resource Additions

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Resource Need	330	680	1010	1440	3400	3810	4360	4850	5290	5700	6130	6570	7000	7420

Resource Options

The resource needs identified above require significant new capacity additions. Screening curves were created for all categories of supply-side options including peaking, intermediate, and baseload capacity to determine which technologies would receive further consideration. (See Appendix J.)

The following technologies were included in the quantitative analysis as potential resource options to meet future capacity needs:

- Pulverized coal - 400 MW, 600 MW, 800 MW, 1,200 MW (2 X 600) and 1,600 MW (2 X 800)
- IGCC – 600 MW
- Natural gas combined-cycle with duct firing – 585 MW
- Natural gas simple-cycle combustion turbine – 564 MW (4-unit plant)
- Nuclear AP 1000 – 2,234 MW (2 X 1117)

Wind and other renewable technologies were not explicitly assumed to be able to deliver material capacity at this time, due primarily to resource constraints in the region. However, Duke Power continues to evaluate opportunities to incorporate new renewable energy generation into its supply portfolio.

Pumped storage can complement baseload generation and will be considered further as future baseload additions are contemplated.

Demand-side programs continue to be an important part of Duke Power's system mix. 100 MW of unspecified Demand-side management (DSM) options were included in the analysis

Refer to Appendix J for details regarding these DSM Options.

Portfolio Options

A screening analysis using a simulation model was conducted to identify the most attractive capacity options under the expected load profile and market conditions, as well as under a range of risk cases. Capacity options were compared within their respective fuel types and operational capabilities, with the most cost-effective options being selected for inclusion in the portfolio analysis phase.

The screening analysis revealed that the economies of scale associated with developing one or two 800 MW coal units at an existing plant site ("brownfield") would likely offer substantially lower construction and operating costs than smaller units. As a result, given the significant capacity need over the planning horizon, only 800 MW and 1600 MW (2 – 800 MW units) coal options were included in the portfolio analysis phase. An 800 MW off-system mine-mouth coal option was also included to evaluate the tradeoff between fuel savings and transmission costs. IGCC was not included in the portfolio analysis because it exhibited higher costs[4] than the other coal options and no known viable options for geological carbon sequestration exist in the service area. Nuclear and natural gas fired capacity options also exhibited cost advantages in the capacity screening process and were therefore included in the portfolio analysis[5].

[4] Without and with investment tax credit.

[5] Portfolios that included new nuclear capacity were also evaluated with a nuclear production tax credit (PTC), as has been outlined in the Energy Policy Act of 2005. Since the ultimate availability for a specific plant is uncertain, both 500 MW and 1,000 MW PTC cases were analyzed for the base assumptions. The 1,000 MW PTC case was also applied in the sensitivity analysis to bound the results.

The following table outlines the planning options that were considered in the portfolio analysis phase:

Plan	New Generation Portfolios
A-1	2 – 800 MW brownfield coal units; 2,300 MW combined cycle (CC); 3,900MW combustion turbine (CT)
A-2	2 – 800 MW brownfield coal units; 800 MW of existing old coal retirements; 2,900 MW CC; 3,900MW CT
A-3	1 – 800 MW brownfield coal unit; 3,500 MW CC; 3,500 MW CT
A-4	1 – 800 MW mine-mouth coal unit; 3,500 MW CC; 3,300 MW CT
B-1	2 – 1,100 MW nuclear units; 1 – 800 MW brownfield coal unit; 1,800 MW CC; 3,000 MW CT
B-2	2 – 1,100 MW nuclear units; 1- 800 MW mine-mouth coal unit; 1,800 MW CC; 2,800 MW CT
B-3	2 – 1,100 MW nuclear units; 2,300 MW CC; 3,000 MW CT (no coal)
B-4	2 – 1,100 MW nuclear units (delayed until 2020); 1 – 800 MW brownfield coal unit; 1,800 MW CC; 3,000 MW CT
B-5	2 – 1,100 MW nuclear units; 2 – 800 MW brownfield coal unit; 600 MW CC; 3,400 MW CT
C-1	3,500 MW CC; 4,100 MW CT (no coal, no nuclear)

In addition, each of the above portfolio options contains 100 MW of notional DSM capacity (of the interruptible load variety). Energy efficiency strategies were evaluated but found to be less cost-effective than interruptible load options.

Portfolio Analysis Insights

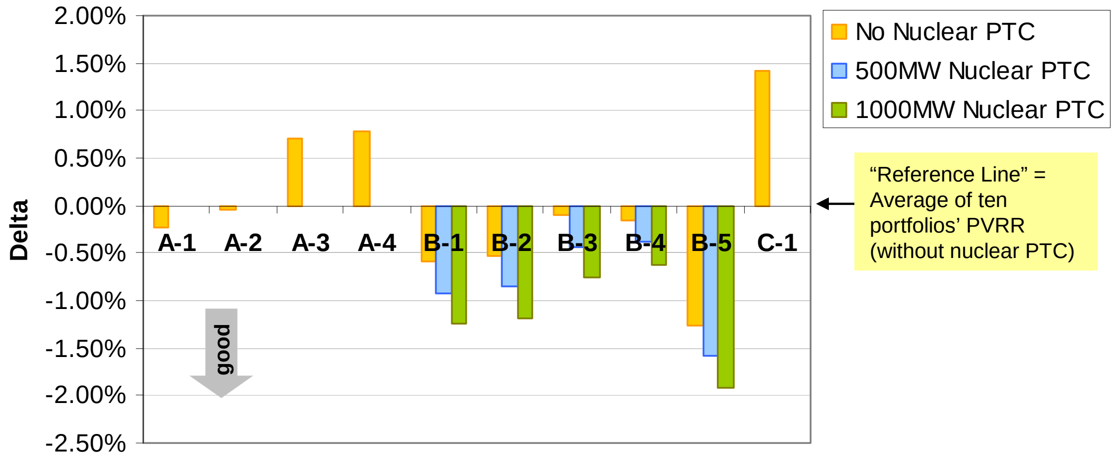
Yearly revenue requirements for various resource planning strategies were calculated based on production cost simulation and levelized capital recovery over a 35-year analysis time frame. Results for the various plans were compared on both a present-value and total-nominal-dollar basis.

It should be noted that the PVRR variances for the results shown below should not be compared across sensitivities (high natural gas prices vs. basecase for example) since the reference line of each sensitivity is based on average costs specific to a given sensitivity.

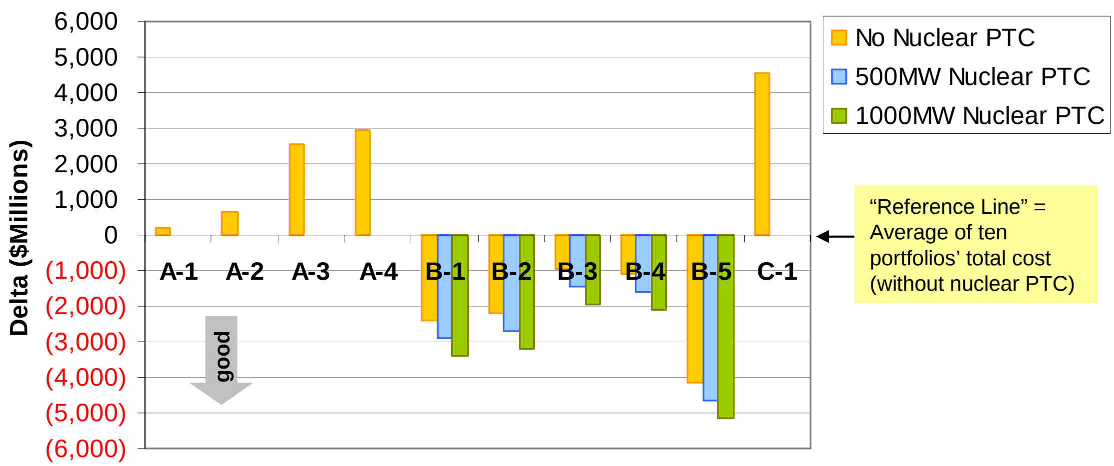
Base Case

The assumptions for the base case include Duke Power's expected load growth, projected commodity prices and expected asset development costs and timing.

PVRR by Plan versus Average PVRR



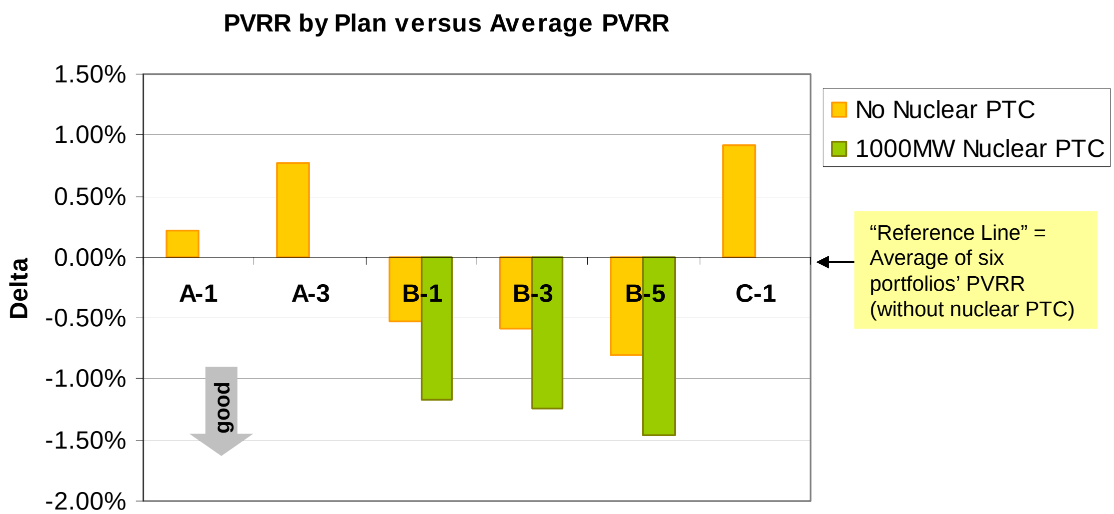
Total Cost 2005-2039 by Plan versus Average Total Cost

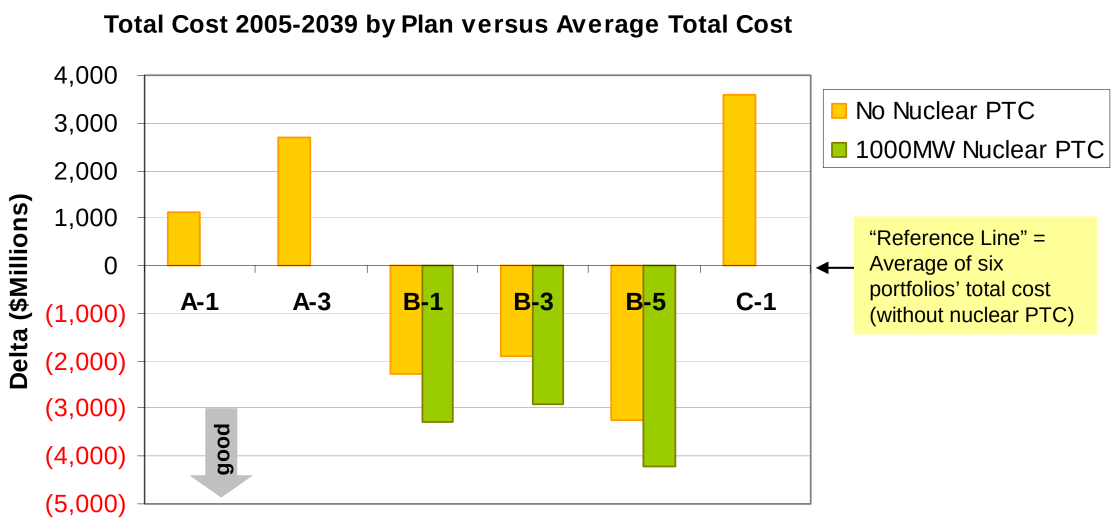


Sensitivities:

Based on insights from the base case analysis six of the portfolios were selected for further analysis.[6] These portfolios were evaluated under a range of sensitivities and scenarios. The results of these analyses are shown below:

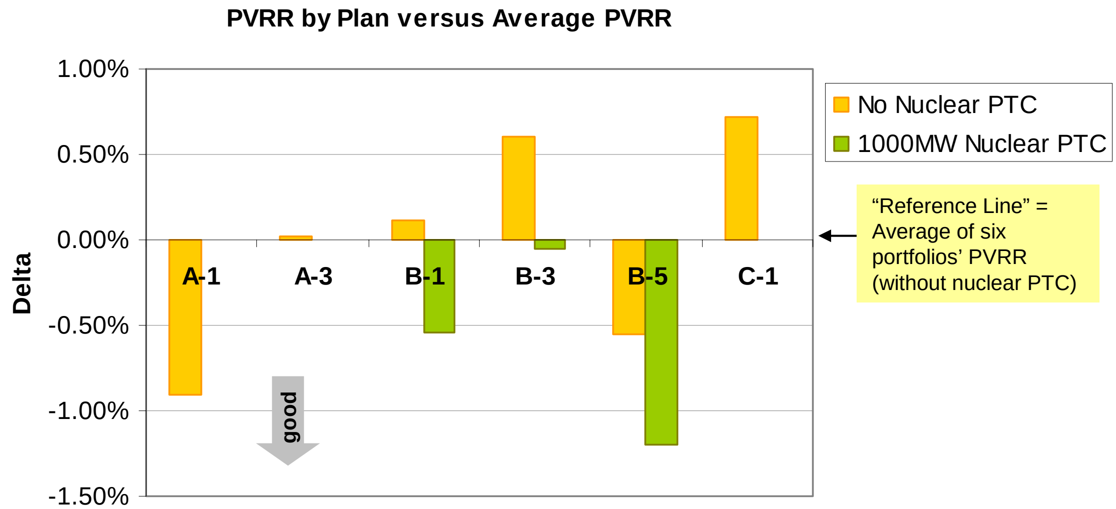
Sensitivity: Coal Construction Costs Increase

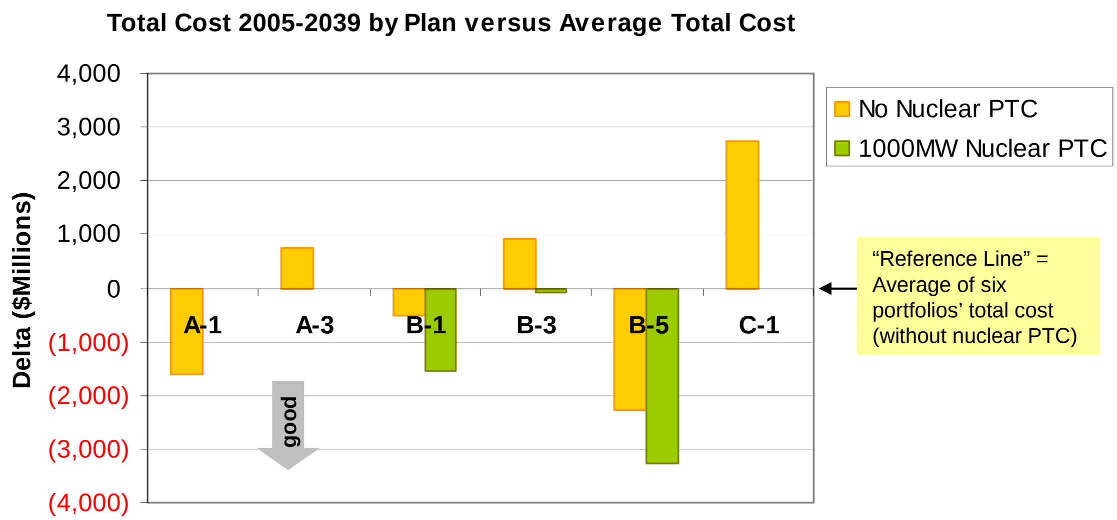




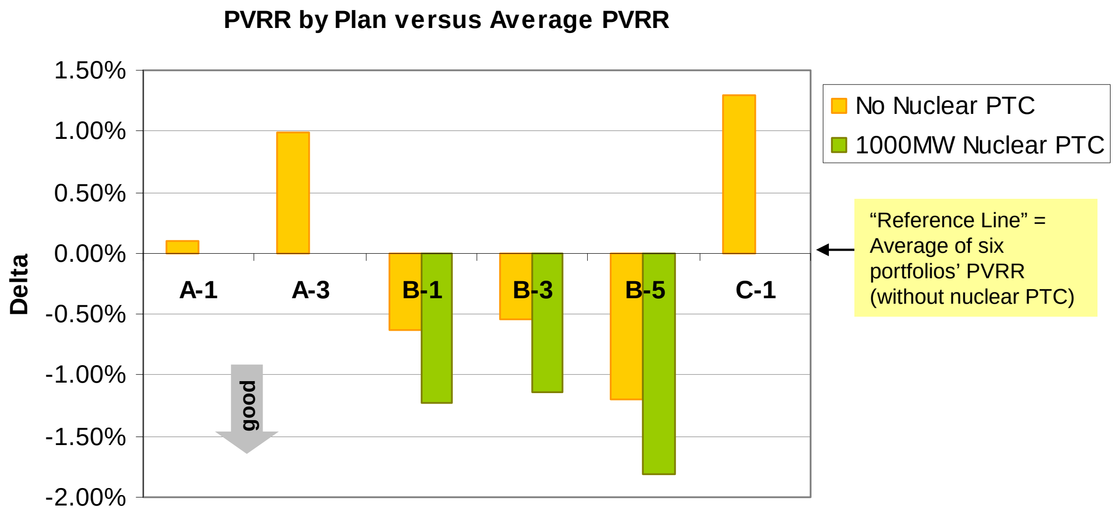
[6] Of the ten portfolios analyzed under the base assumptions, six were included in the sensitivity analysis. The four excluded portfolios represented minor (but more costly) strategic deviations relative to other portfolios that were carried through the remaining sensitivity analysis.

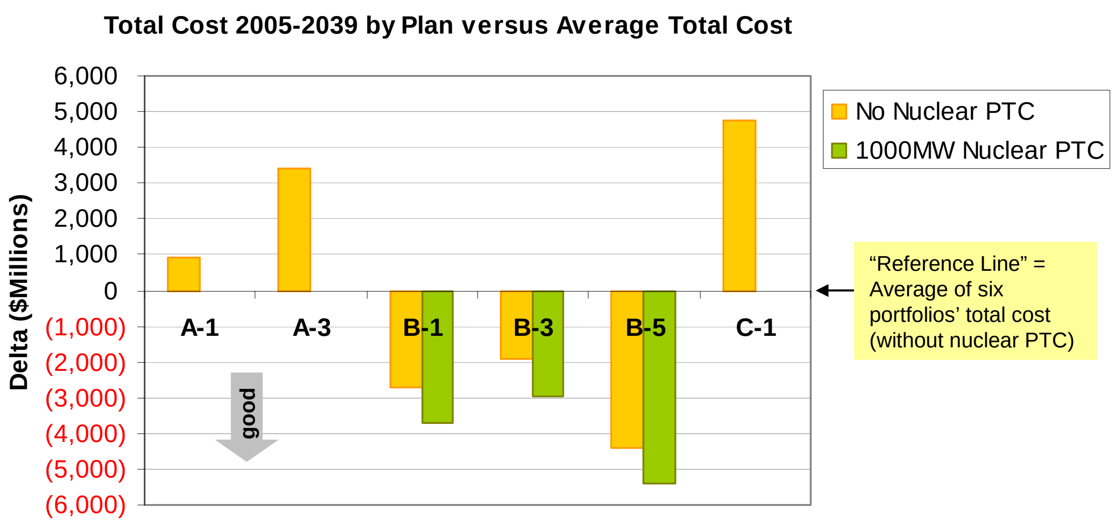
Sensitivity: Nuclear Construction Costs Increase



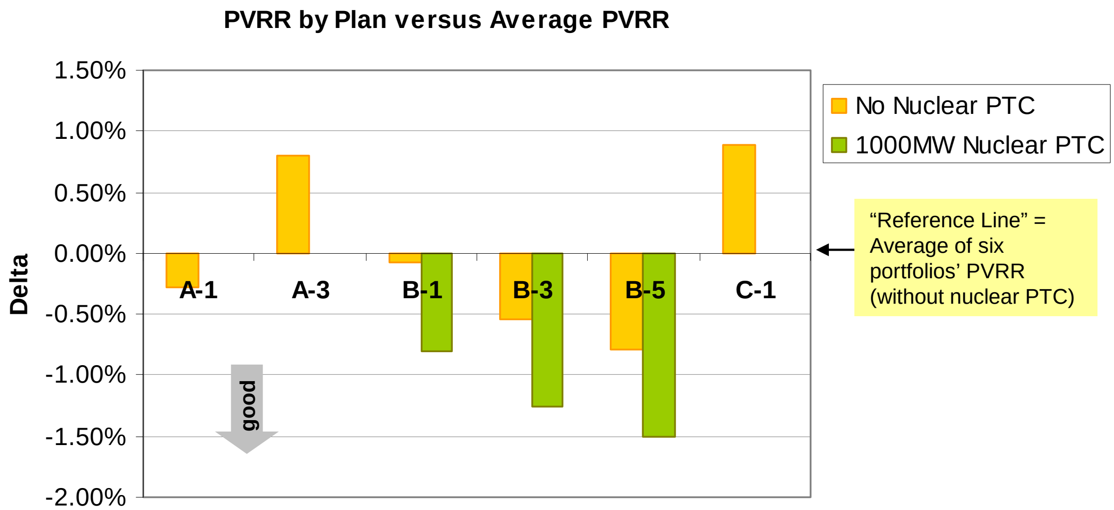


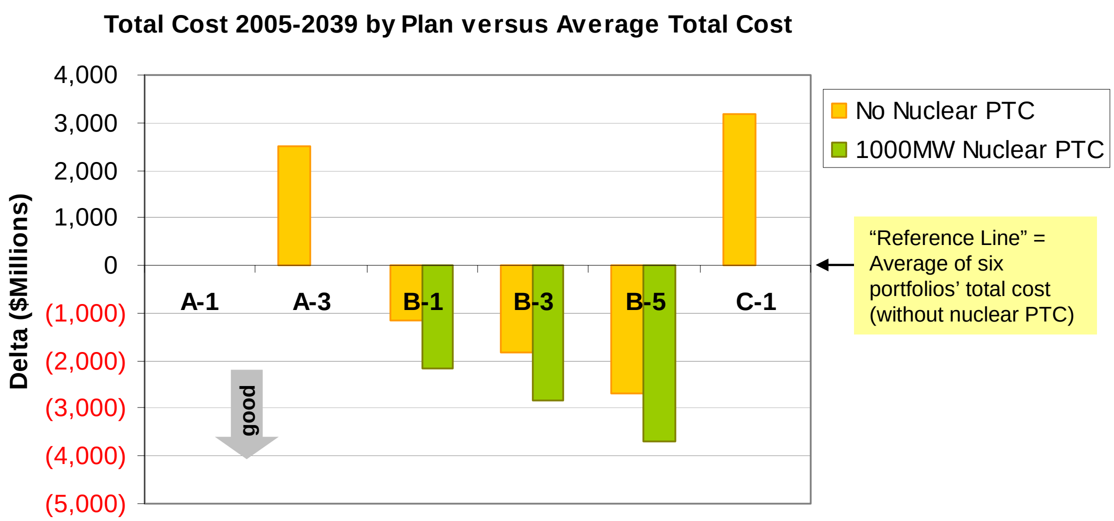
Sensitivity: High Load



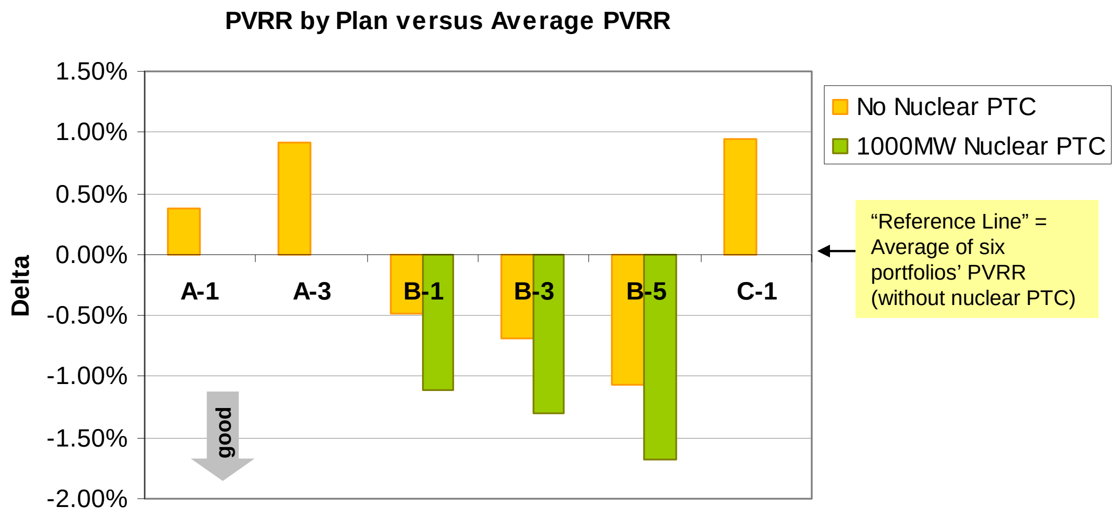


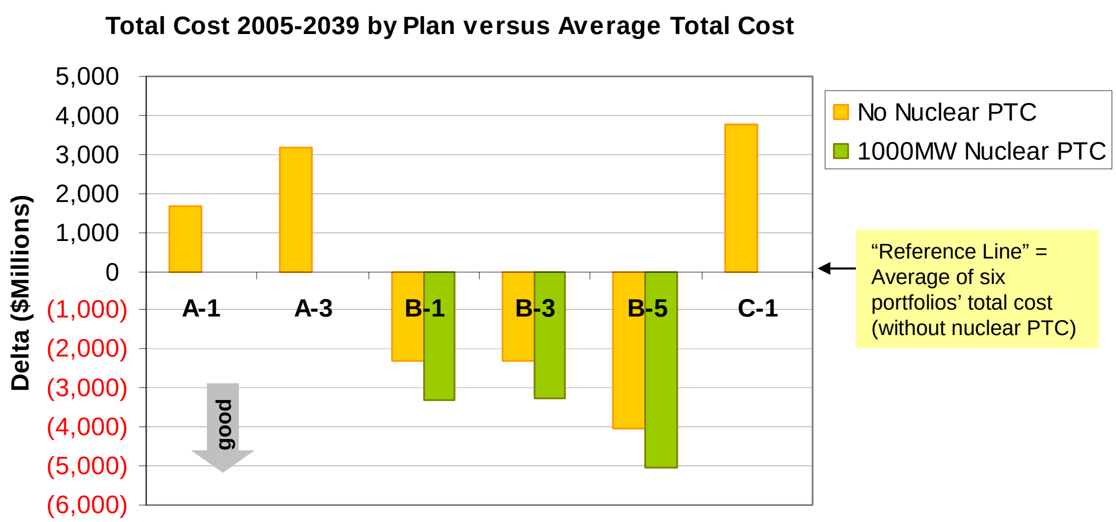
Sensitivity: Low Load



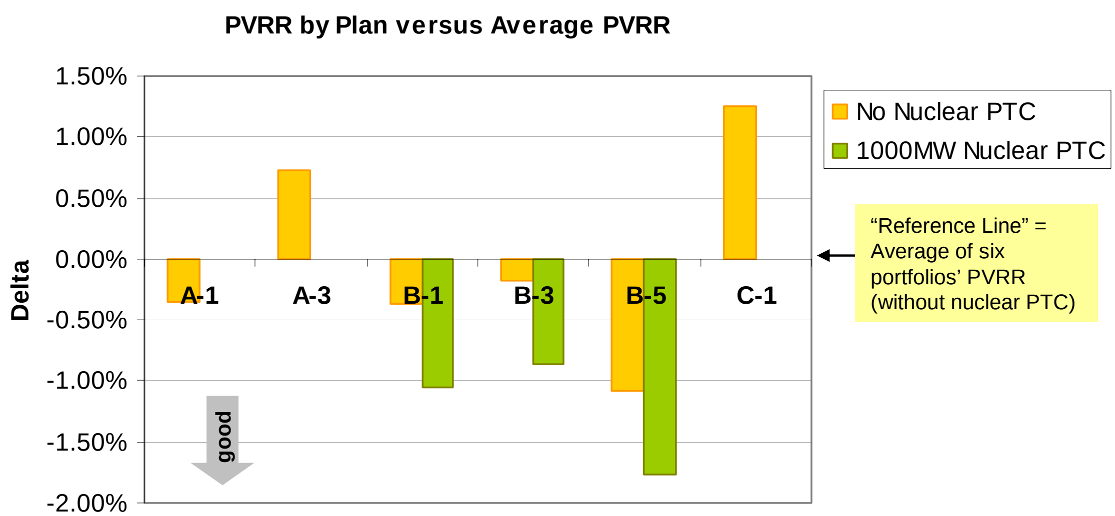


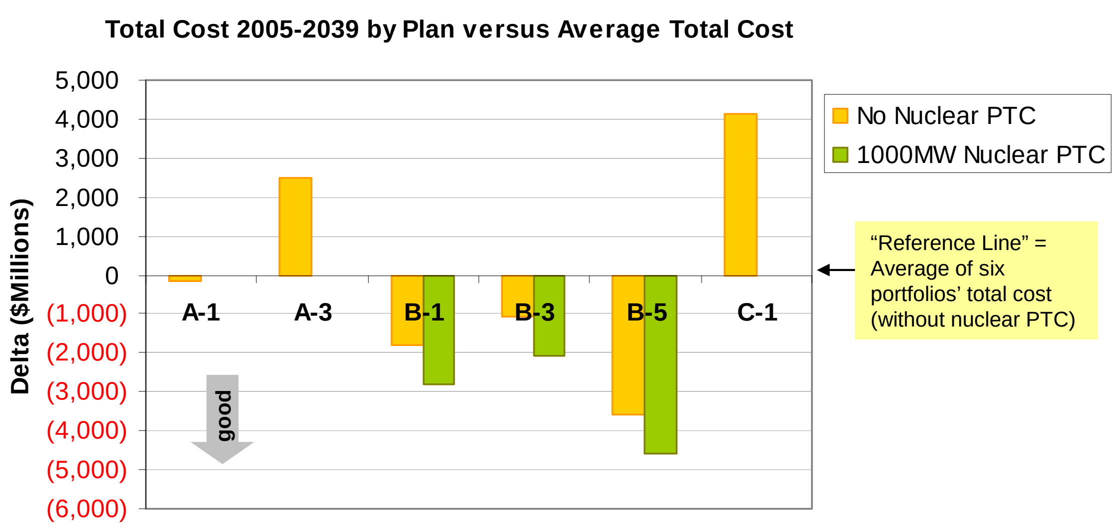
Sensitivity: High Coal Prices



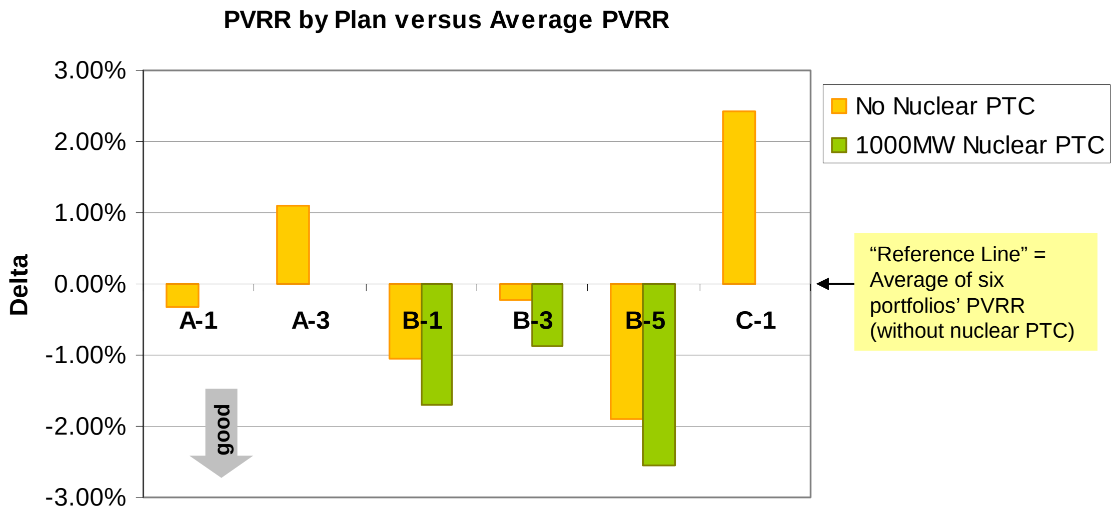


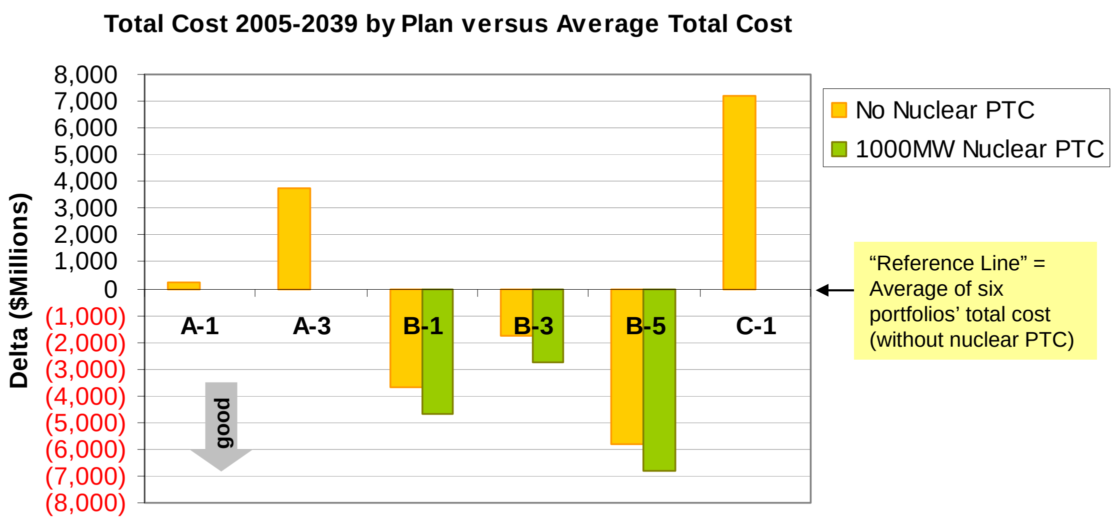
Sensitivity: Low Coal Prices



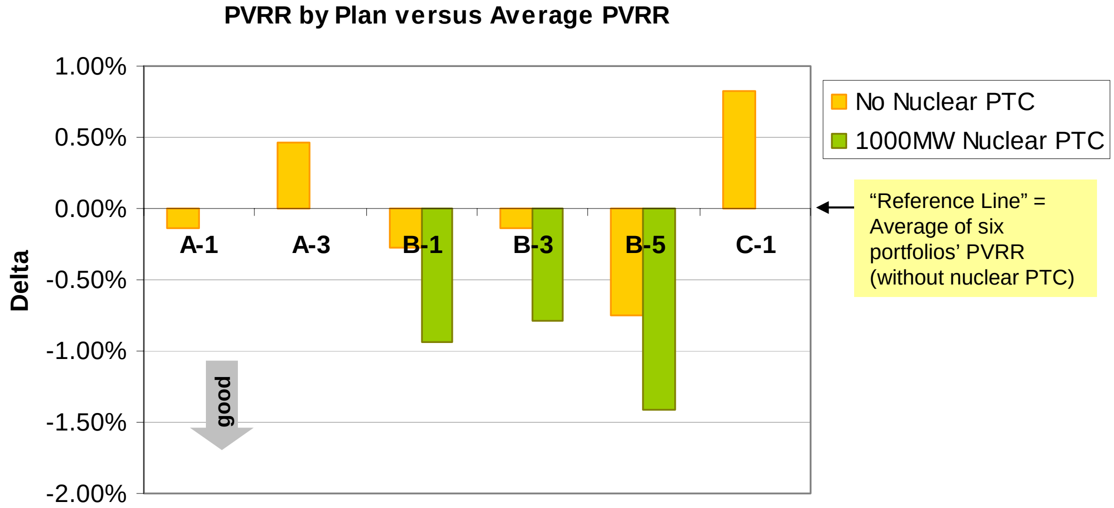


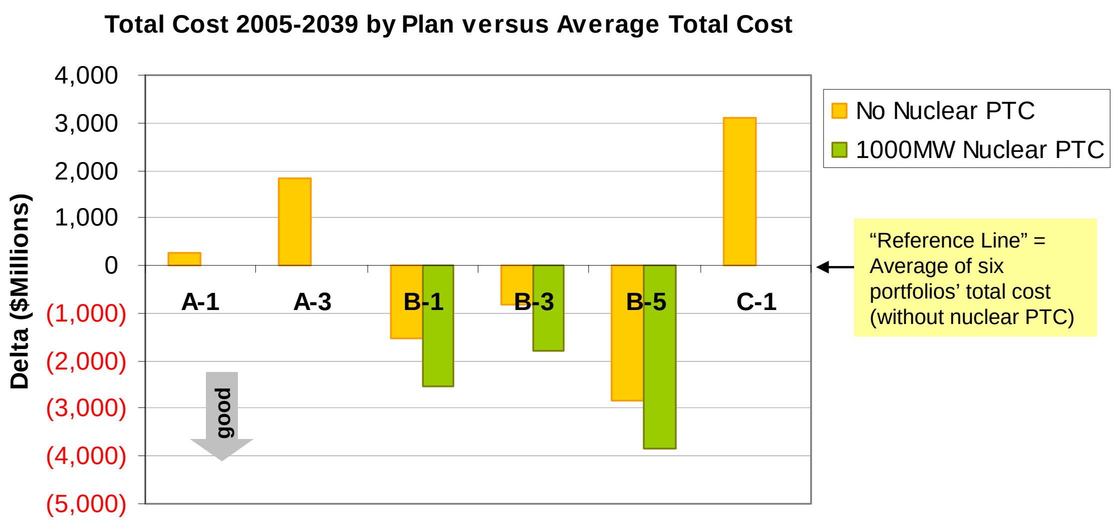
Sensitivity: High Natural Gas Prices



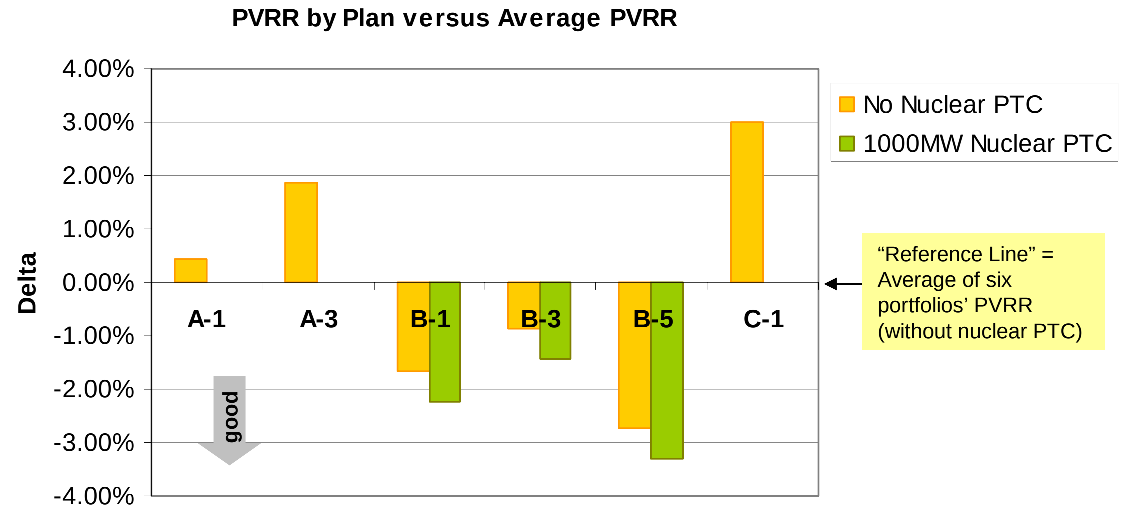


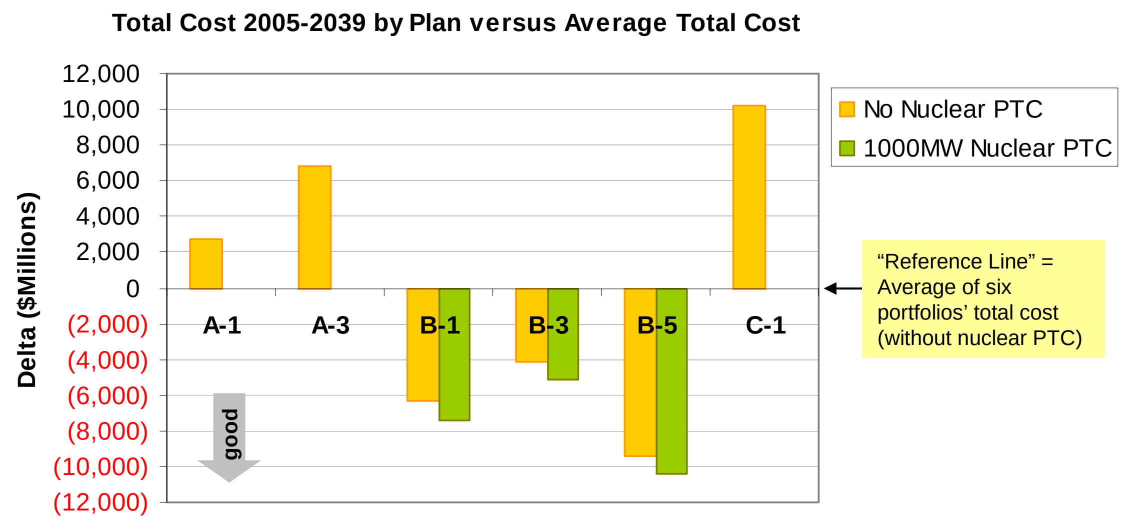
Sensitivity: Low Natural Gas Prices



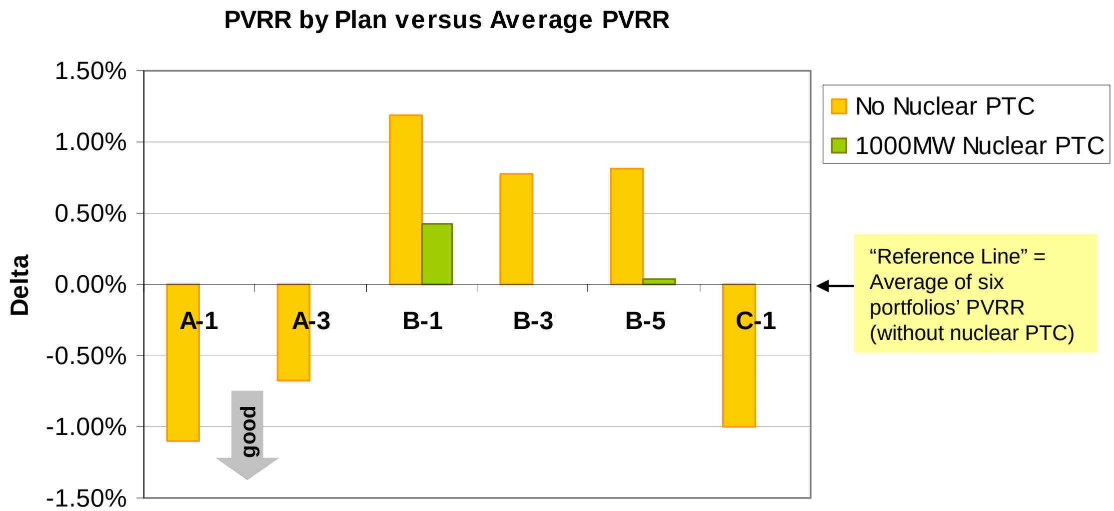


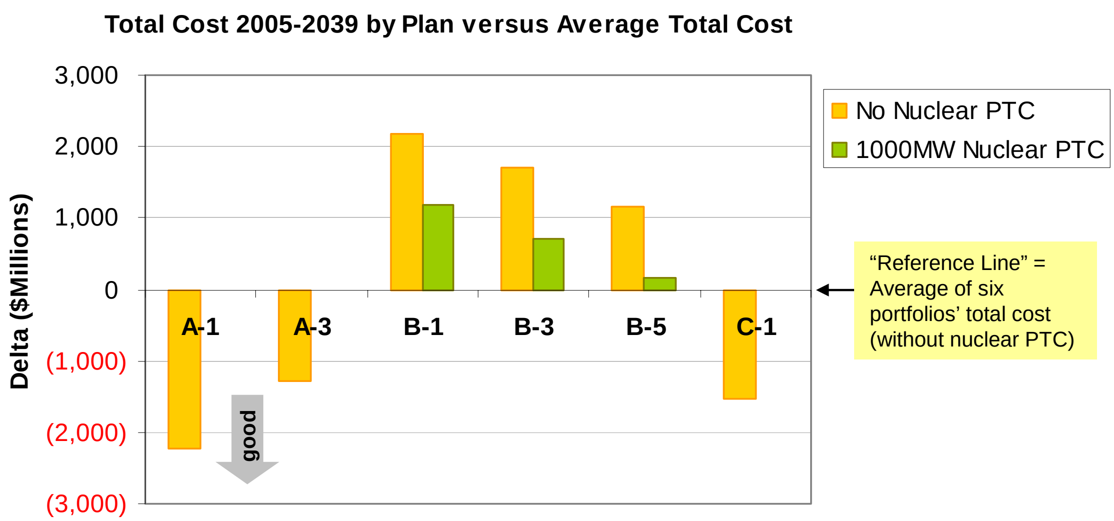
Sensitivity: Constant Higher Coal and Natural Gas Prices



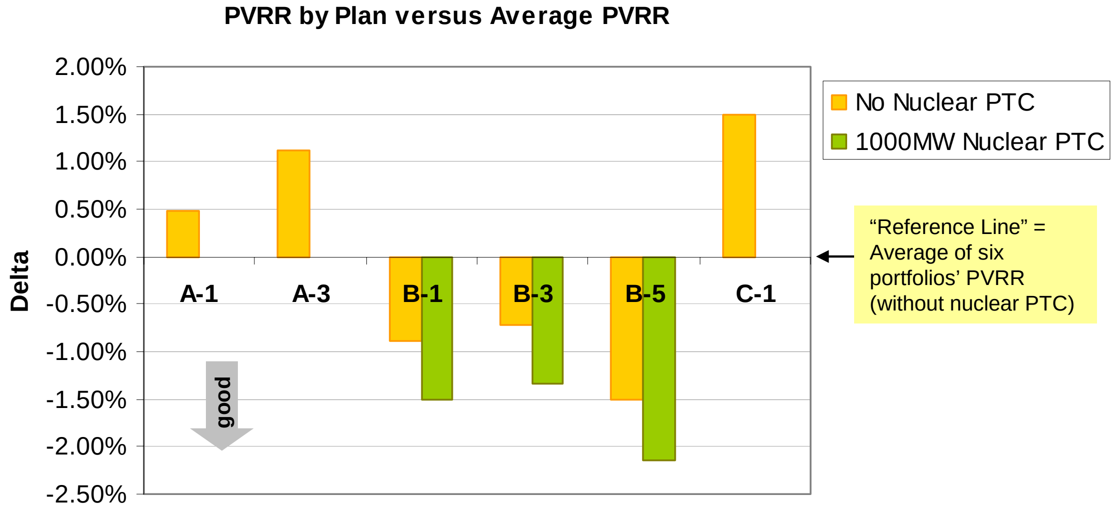


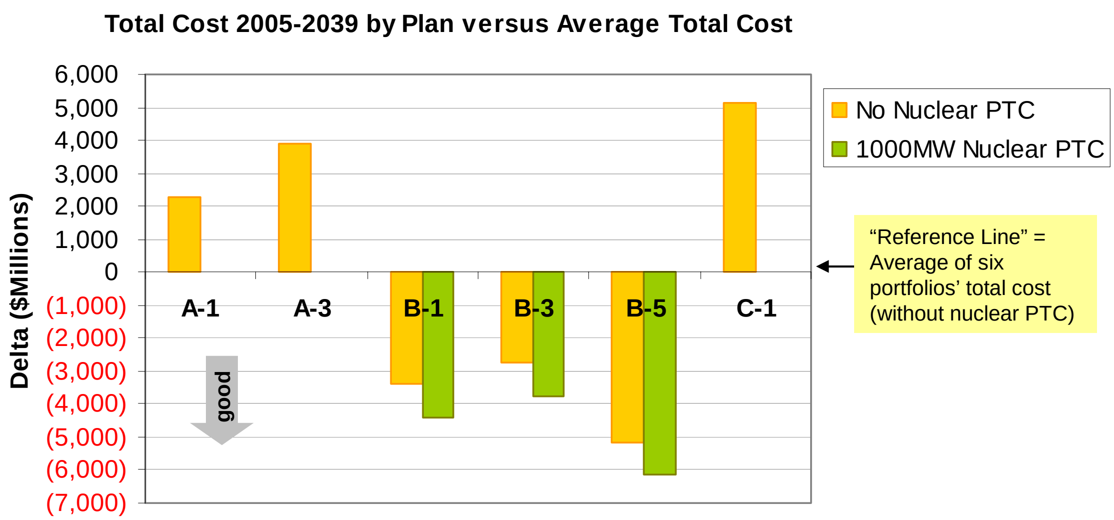
Sensitivity: Constant Lower Coal and Natural Gas Prices



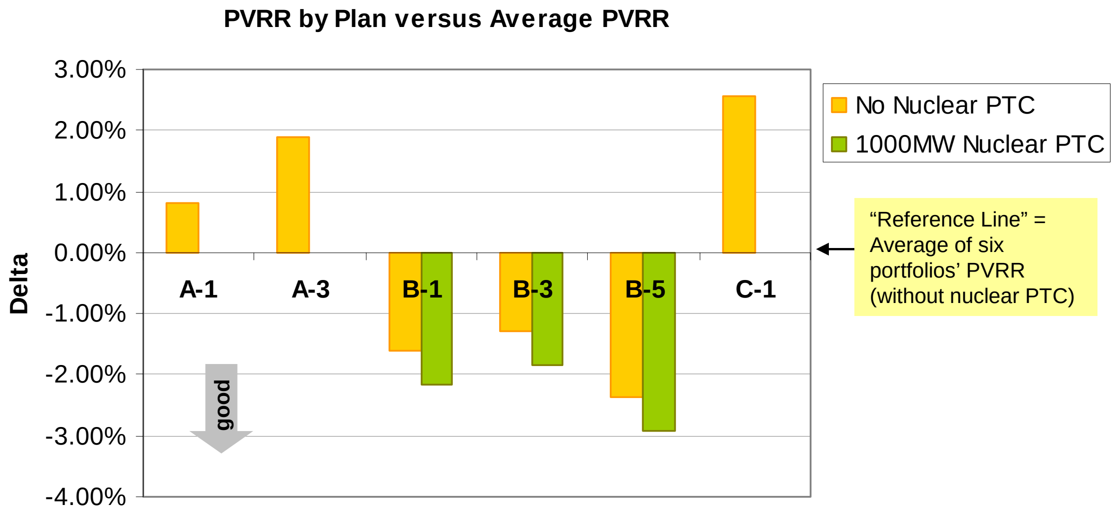


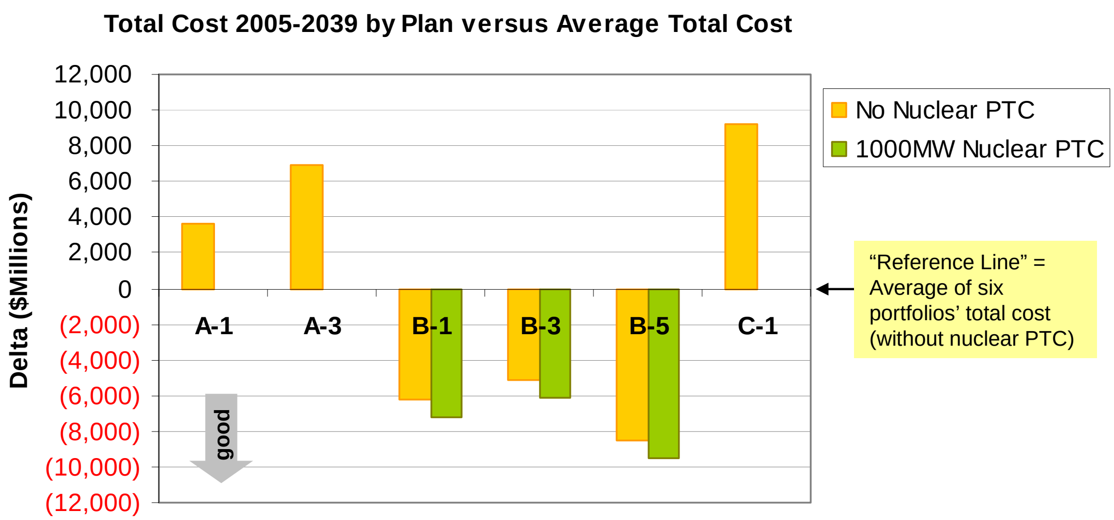
Sensitivity: Carbon Tax



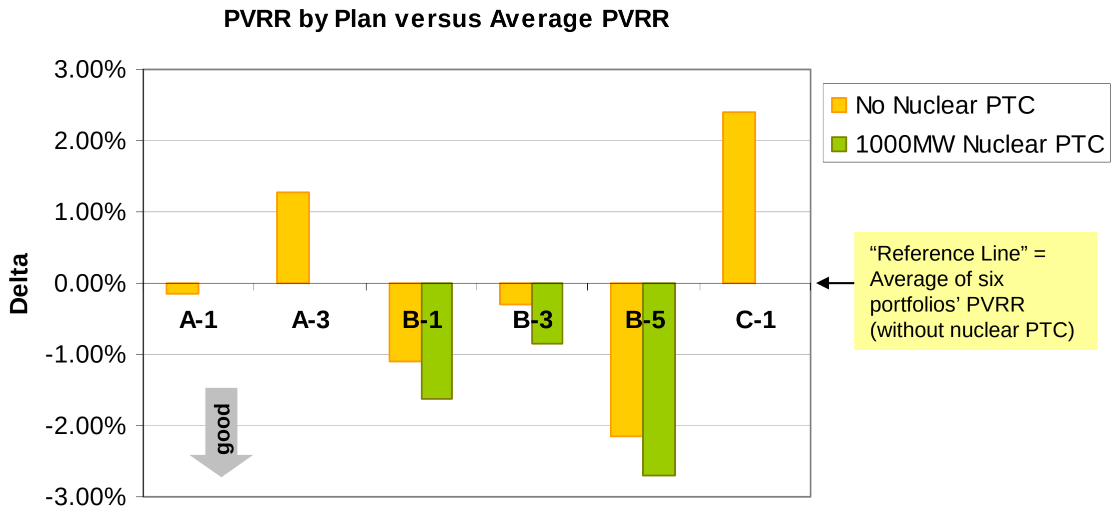


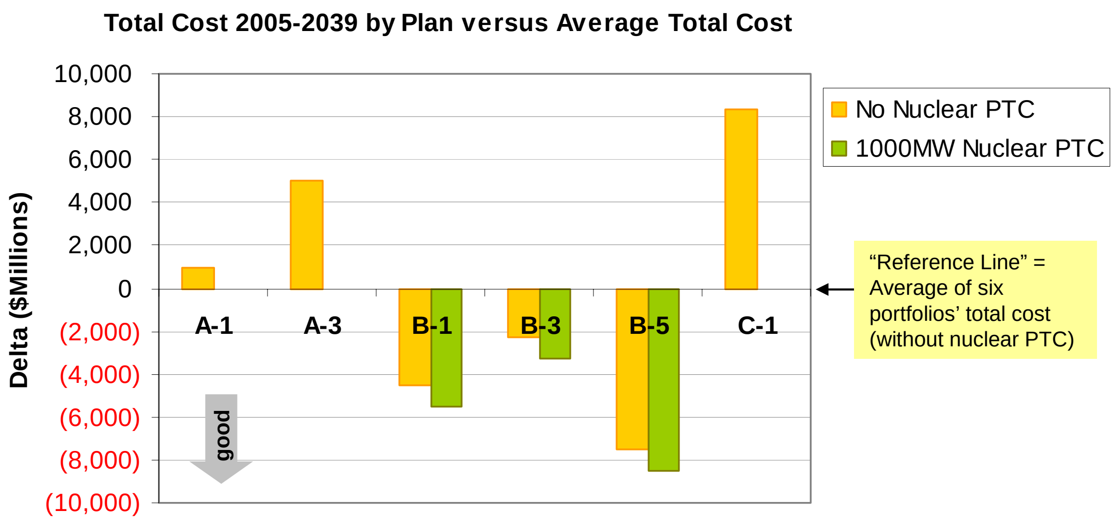
Scenario: Constant Higher Coal and Natural Gas Prices and Coal Construction Costs Increase



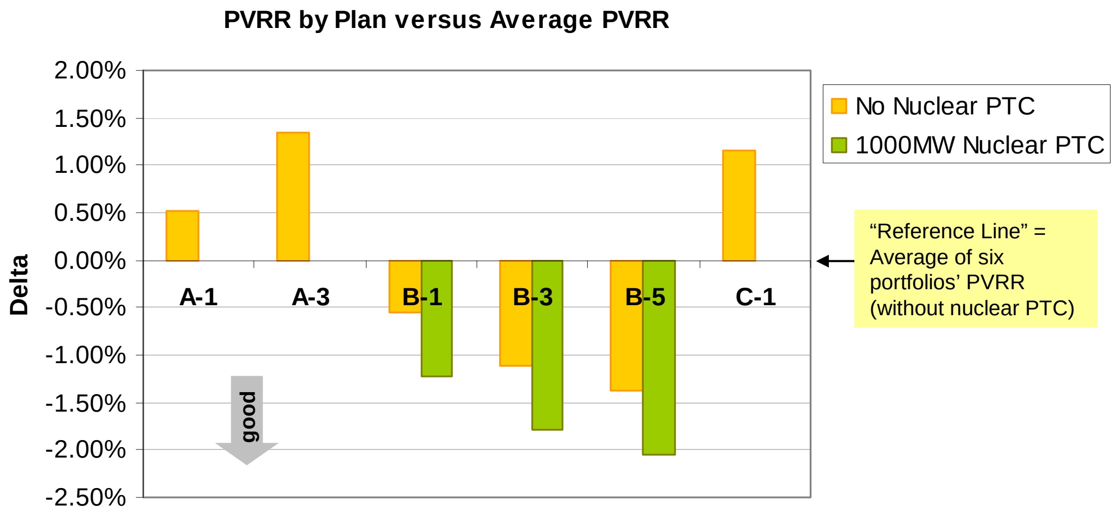


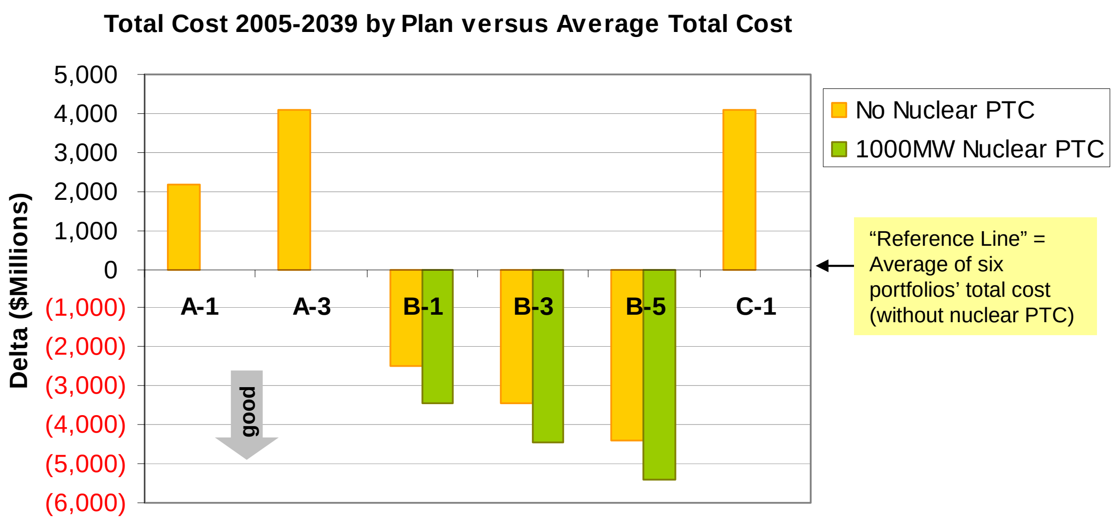
Scenario: Constant Higher Coal and Natural Gas Prices and Nuclear Construction Costs Increase





Scenario: Carbon Tax and Low Load





The results of the quantitative analysis indicate that significant additions of peaking, intermediate and baseload capacity to the Duke Power portfolio are required over the next decade. The projected relative revenue requirements of the portfolio options demonstrate the value of new nuclear and coal capacity to customers, not only under base assumptions, but also under the wide range of sensitivities and scenarios considered.

In nearly all of the sensitivities and scenarios tested, the plan featuring 1,600 MW of new coal capacity and 2,234 MW of new nuclear capacity outperformed all other plans under consideration (see Appendix E for a Seasonal Projection of Load, Capacity, and Reserves Table reflecting the generation strategy that performs best under a variety of sensitivities and scenarios). Only scenarios with constant lower natural gas prices or with large increases in nuclear development costs produced different results. The consistency among the results was driven primarily by the significant fuel-cost advantage of nuclear generation and the capital and operational cost savings associated with siting new coal units at an existing plant.

In addition to on-system development, an off-system coal capacity option was included in the base case portfolio analysis to evaluate the benefits of coal mine proximity, along with the costs of importing power from outside the Duke Power control area. Off-system coal capacity options showed a modest cost disadvantage compared to the on-system coal option, based on assumed transmissions costs. However, future changes in the transmission cost structure could enhance the competitiveness of an off-system asset.

The results suggest that retiring older coal units would not be justified on a production cost basis. Despite some potential reduction in capacity factors as combined-cycle capacity is added, the costs of maintaining those older units are expected to be less burdensome on customers than retiring the units and investing in additional capacity to achieve the target reserve margin.

In addition, analysis results demonstrated the value of adding natural gas-fired combined-cycle capacity for intermediate generation needs. Simple-cycle combustion turbines are also prominent in each of the plans to meet peaking needs.

APPENDIX B: CROSS-REFERENCE OF ANNUAL PLAN REQUIREMENTS

The following table cross-references Annual Plan regulatory requirements for North Carolina and South Carolina, and identifies where those requirements are discussed in the Plan.

Requirement	Location
Quantitative Analysis	Appendix A
2005 FERC Form 715	Appendix C
Reserve Margin Explanation and Justification	Pgs. 22-23 and Appendix D for DSM Activation History.
Transmission System Adequacy	Pgs. 8-9
Load Forecast and Seasonal Projections of Load Capacity and Reserves for Duke Power	Pgs. 18-21(load), pg. 24 Load and Resource Balance, Appendix E for Seasonal Projection of LCR for Duke Power
Existing Plants in Service	Pgs. 9-12
Generating Units Under Construction or Planned	Appendix F
Proposed Generating Units at Locations Not Known	Appendix G
Generating Units Projected To Be Retired	Pgs. 21-22
Generating Units with Plans for Life Extension	Pgs. 99-100 under Hydroelectric Relicensing
Transmission Lines and Other Associated Facilities that are Planned or Under Construction	Appendix H
Generating or Transmission Lines Subject to Construction Delays	Appendix I
Demand-Side Options and Supply-Side Options Referenced in the Annual Plan	Pgs. 13-14 for existing DSM and Appendix J for supply-side and DSM options considered in the planning

	process
Wholesale Purchase Power Commitments Reflected in the Annual Plan	Pgs. 15-17
Wholesale Power Sales Commitments Reflected in the Annual Plan	Pg. 14
Supplier's Program for Meeting the Requirements Shown in its Forecast in an Economic and Reliable Manner, including DSM and Supply-Side Options	Although entire document refers to Duke Power's resource plan to meet the load obligation, please refer to pgs. 13-14 and Appendix J for demand-side options, Appendix J for supply-side options, Pgs. 25-27 and Appendix E for Seasonal Projections of LCR for Duke Power
Brief description and summary of cost-benefit analysis, if available, of each option considered, including those not selected	Appendix J for supply-side and demand-side options
Supplier's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable	Entire document, especially pgs. 17 and 96-98 for environmental and pg. 12 for fuel
Non-utility Generation, Customer-owned Generation, Standby Generation	Appendix K
Duke Power's 2004 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 424 and 425	Appendix L
Other Information (economic development)	Appendix M

APPENDIX C: 2005 FERC Form 715

The 2005 FERC Form 715 filed April 2005 is confidential and filed under seal.

APPENDIX D: CURTAILABLE SERVICE PILOT & DSM PROGRAMS

The following describes the existing Curtailable Service pilot and DSM programs. The tables list the existing DSM projection and activation history.

Curtailable Service

Participants agree in individual monthly contracts to voluntarily reduce their electrical loads to specified levels upon request by Duke Power. For any curtailable service month, each participating customer is asked to contract for a curtailable load by specifying a firm contract demand for that month. Customers who make that commitment to curtail service receive a capacity payment for the month and also an energy payment if curtailment is actually requested and the customer actually curtails load. No payments are made to customers who do not make a curtailable load commitment or who make a commitment but fail to curtail load at the Company's request. The Duke Power Curtailable Service pilot program targets the Commercial and Industrial sectors and currently has 11 customers.

Demand-Side Programs

The following programs are designed to provide a source of interruptible capacity to Duke Power whenever it encounters capacity problems:

Demand Response – Load Control Curtailment Programs

Residential Air Conditioning Direct Load Control
Participants receive billing credits during the billing months of July through October in exchange for allowing Duke Power the right to interrupt electric service to their central air conditioning systems.

Residential Water Heating Direct Load Control
Participants receive billing credits for each billing month in exchange for allowing Duke Power the right to interrupt electric service to their water heaters. Water heating load control was closed in 1993 to new customers in North Carolina and South Carolina.

Demand Response – Interruptible Programs

Interruptible Power Service
Participants agree contractually to reduce their electrical loads to specified levels upon request by Duke Power. If customers fail to do so during an interruption, they receive a penalty for the increment of demand exceeding the specified level.

Standby Generator Control
Participants agree contractually to transfer electrical loads from the Duke Power source to their standby generators upon request by Duke Power. The generators in this program do not operate in parallel with Duke Power's system and therefore, cannot "backfeed"

(e.g., export power) into the Duke Power system. Participating customers receive payments for capacity and/or energy, based on the amount of capacity and/or energy transferred to their generators.

Other demand-side management programs include:

Demand Response – Time of Use Programs

Residential Time-of-Use
This category of rates for residential customers incorporates differential seasonal and time-of-day pricing that encourages customers to use less electricity during on-peak time periods and more during off-peak periods.

General Service and Industrial Time-of-Use
This category of rates for general service and industrial customers incorporates differential seasonal and time-of-day pricing that encourages customers to use less electricity during on-peak time periods and more during off-peak periods.

Hourly Pricing for Incremental Load and Hourly Pricing – Flex
This category of rates for general service and industrial customers incorporates prices that reflect Duke Power's estimation of hourly marginal costs. In addition, a portion of the customer's bill is calculated under their embedded-cost rate. Customers on this rate can choose to modify their usage depending on hourly prices.

Energy Efficiency Programs

Residential Energy Star
This rate promotes the development of homes that are significantly more energy-efficient than a standard home. Homes are certified when they meet the standards set by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy. To earn the symbol, a home must be at least 30 percent more efficient than the national Model Energy Code for homes, or 15 percent more efficient than the state energy code, whichever is more rigorous. Independent third-party inspectors test the homes to ensure they meet the standards to receive the Energy Star symbol. The independent home inspection is the responsibility of the homeowner or builder. Electric space heating and/or electric domestic water heating are not required.

Residential Service Water Heating
This program shifts a participating customer's water heating usage to off-peak periods as determined by Duke Power. The program is currently available in accordance with rate schedule WC. The customer is billed at a lower rate for all water heating energy consumption in exchange for allowing Duke Power to control the water heater.

Existing Residential Housing Program
This residential program encourages increased energy efficiency in existing residential structures. The program consists of loans for heat pumps, central air conditioning

systems, and energy-efficiency measures such as insulation, HVAC tune-ups, duct sealant, etc.

Special Needs Energy Products Loan Program
This residential program encourages increased energy efficiency in existing residential structures for low-income customers. The program consists of loans for heat pumps, central air conditioning systems and energy-efficiency measures such as insulation, HVAC tune-ups, duct sealant, etc.

Existing DSM Program Details

Program	Target Market Segment	Customers	Expected Total MW Reduction (Summer)	Expected Total MW Reduction (2005/2006 Winter)
Residential Air Conditioning Direct Load Control	Residential	189,649	324	0
Residential Water Heating Direct Load Control	Residential	34,644	6	22
Interruptible Power Service	Commercial and Industrial	158	342	285
Standby Generator Control	Commercial and Industrial	159	94	88
Energy Efficiency	All Segments	Results are implicit in the load forecast		

INTERRUPTIBLE DEMAND SIDE PROGRAMS DATA

Number of Customers

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
AC/LC	191,897	189,649	187,401	185,153	182,905	180,657	178,409	176,161	173,913	171,665	169,417	167,169	164,921	162,673	162,673	162,673
WH/LC	36,160	34,644	33,127	31,611	30,095	28,579	27,063	25,546	24,030	22,514	20,998	19,482	17,965	16,449	16,449	16,449
IS	162	158	154	150	146	142	138	134	130	130	130	130	130	130	130	130
SG	156	159	162	165	168	171	174	177	180	183	186	189	192	195	198	201

Demand
(Mw)

	2005		2006		2007		2008		2009		2010		2011		2012	
	Winter	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
AC/LC	0	332	0	324	0	316	0	308	0	301	0	294	0	287	0	281
WH/LC	23	6	22	6	20	6	19	5	18	5	17	5	16	4	15	4
IS	292	351	285	342	278	334	270	325	263	316	256	308	249	299	242	290
SG	86	92	88	94	89	96	91	98	93	99	94	101	96	103	98	105
Total	**401**	**782**	**395**	**766**	**387**	**751**	**380**	**737**	**374**	**721**	**367**	**708**	**361**	**694**	**355**	**680**

Demand
(Mw)

	2013		2014		2015		2016		2017		2018		2019		2020	
	Winter	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
AC/LC	0	275	0	269	0	264	0	258	0	253	0	248	0	248	0	248
WH/LC	14	4	13	4	12	3	11	3	10	3	9	3	9	3	9	3
IS	234	282	234	282	234	282	234	282	234	282	234	282	234	282	234	282
SG	99	107	101	108	103	110	104	112	106	114	107	115	109	117	111	119
Total	**347**	**668**	**348**	**663**	**349**	**659**	**349**	**655**	**350**	**652**	**350**	**647**	**352**	**649**	**354**	**651**

Estimated Customer Credits

	2005	2006	2007	2008	2009	2010
AC/LC	$ 6,141,000	$ 6,069,000	$ 5,997,000	$ 5,925,000	$ 5,853,000	$ 5,781,000
WH/LC	$ 868,000	$ 831,000	$ 795,000	$ 759,000	$ 722,000	$ 686,000
IS	$ 13,046,000	$ 12,724,000	$ 12,402,000	$ 12,080,000	$ 11,757,000	$ 11,435,000
SG	$ 2,856,000	$ 2,911,000	$ 2,966,000	$ 3,021,000	$ 3,075,000	$ 3,130,000
Total	**$22,911,000**	**$22,535,000**	**$22,160,000**	**$21,785,000**	**$21,407,000**	**$21,032,000**

Energy
(kwh)

AC/LC	None
WH/LC	None
IS	None
SG	None

Target Market Segment

AC/LC	Residental
WH/LC	Residental
IS	Commercial & Industrial
SG	Commercial & Industrial

DEMAND-SIDE MANAGEMENT ACTIVATION HISTORY

Time Frame	**Program**	**Times Activated**	**Reduction Expected**	**Reduction Achieved**
9/2005	None			
8/04 – 8/05	None			
8/03 – 8/04	None			
8/02 – 8/03	None			
8/01 – 8/02	Standby Generators	1 Capacity Need	80 MW	20 MW
8/01 – 8/02	Interruptible Service	1 Capacity Need	403 MW	370 MW
8/00 – 8/01	Standby Generators	1 Capacity Need	70 MW	70 MW
7/99 – 8/00	Standby Generators	1 Capacity Need	70 MW	70 MW
9/97 – 9/98	Standby Generators	2 Capacity Needs	68 MW	58 MW
9/97 – 9/98	Interruptible Service	1 Capacity Need	570 MW	500 MW
9/96 – 9/97	Standby Generators	4 Capacity Needs	62 MW	50 MW
9/96 – 9/97	Interruptible Service	1 Capacity Need	650 MW	550 MW

DEMAND-SIDE MANAGEMENT TEST HISTORY

Time Frame	Program	Times Activated	Reduction Expected	Reduction Achieved
9/2005	Air Conditioners	2 Cycling Tests	N/A	N/A
9/2005	Water Heaters	2 Cycling Tests	N/A	N/A
9/2005	Standby Generators	Monthly Test	N/A	N/A
8/04 - 8/05	Air Conditioners	Load Test	140 MW	148 MW
		2 Cycling Tests	N/A	N/A
8/04 – 8/05	Water Heaters	Load Test	2 MW	Included in Air Conditioners
		2 Cycling Tests	N/A	N/A
8/04 – 8/05	Standby Generators	Monthly Test	N/A	N/A
8/04 – 8/05	Interruptible Service	Communication Test	N/A	N/A
8/03 – 8/04	Air Conditioners	Load Test	110 MW	170 MW
		Cycling Test	N/A	N/A
8/03 – 8/04	Water Heaters	Cycling Test	N/A	N/A
8/03 – 8/04	Standby Generators	Monthly Test	N/A	N/A
8/03 – 8/04	Interruptible Service	Communication Test	N/A	N/A
8/02 – 8/03	Air Conditioners	2 Cycling Tests and 1 Load Test 1 Load Test	N/A 88 MW 120 MW	N/A 122 MW 195 MW
8/02 – 8/03	Water Heaters	2 Cycling Tests 1 Load Test 1 Load Test	N/A 6 MW 5 MW	N/A Included in Air Conditioners
8/02 – 8/03	Standby Generators	Monthly Test	N/A	N/A
8/02 – 8/03	Interruptible Service	2 Communication Tests	N/A	N/A
8/01 – 8/02	Air Conditioners	3 Cycling Tests and 1 Load Test	N/A 150 MW	N/A 151 MW
8/01 – 8/02	Water Heaters	3 Cycling Tests and 1 Load Test	N/A 6 MW	N/A Included in Air Conditioners
8/01 – 8/02	Standby Generators	Monthly Test	N/A	N/A
8/01 – 8/02	Interruptible Service	1 Communication Test	N/A	N/A
8/00 – 8/01	Air Conditioners	1 Communication Test	N/A	N/A
8/00 – 8/01	Water Heaters	1 Communication Test	N/A	N/A

8/00 – 8/01	Standby Generators	Monthly Test	N/A	N/A
8/00 – 8/01	Interruptible Service	1 Communication Test	N/A	N/A
7/99 – 8/00	Air Conditioners	1 Load Test	170 – 200 MW	175 – 200 MW
7/99 – 8/00	Water Heaters	1 Load Test	6 MW	Included in Air Conditioners
7/99 – 8/00	Standby Generators	Monthly Test	N/A	N/A
7/99 – 8/00	Interruptible Service	1 Communication Test	N/A	N/A
9/98 – 7/99	Air Conditioners	None	N/A	N/A
9/98 – 7/99	Water Heaters	None	N/A	N/A
9/98 – 7/99	Standby Generators	Monthly Test	N/A	N/A
9/98 – 7/99	Interruptible Service	1 Communication Test	N/A	N/A
9/97 – 9/98	Air Conditioners	1 Load Test	180 MW	170 MW
9/97 – 9/98	Water Heaters	1 Communication Test	N/A	N/A
		1 Load Test	7 MW	7 MW
9/97 – 9/98	Standby Generators	Monthly Test	N/A	N/A
9/97 – 9/98	Interruptible Service	1 Communication Test	N/A	N/A
9/96 – 9/97	Air Conditioners	1 Communication Test	N/A	N/A
9/96 – 9/97	Water Heaters	None	N/A	N/A
9/96 – 9/97	Standby Generators	Monthly Test	N/A	N/A
9/96 – 9/97	Interruptible Service	2 Communication Tests	N/A	N/A

APPENDIX E: SEASONAL PROJECTION OF LOAD, CAPACITY & RESERVES

The following table represents the generation strategy that performs best under a variety of sensitivities and scenarios to reflect the seasonal projection of load, capacity and reserves for Duke Power.

Seasonal Projections of Load, Capacity, and Reserves

W = WINTER, S = SUMMER	W 05/06	S 2006	W 06/07	S 2007	W 07/08	S 2008	W 08/09	S 2009	W 09/10	S 2010	W 10/11	S 2011	W 11/12	S 2012	W 12/13
Forecast															
1 Duke System Peak	15,425	17,376	15,815	17,918	15,934	18,236	15,878	18,343	16,001	18,635	16,936	19,689	17,119	20,026	17,301
Cumulative System Capacity															
2 Generating Capacity	19,976	19,257	19,967	19,236	19,979	19,235	19,627	18,908	19,616	18,924	19,535	18,518	19,237	18,518	19,237
3 Capacity Additions	0	2	0	50	0	0	0	0	50	0	0	0	0	0	0
4 Capacity Derates	0	0	(12)	(26)	(25)	(25)	0	(11)	(23)	0	0	0	0	0	0
5 Capacity Retirements	0	(7)	0	0	0	(88)	0	0	0	(108)	(298)	0	0	0	0
6 Cumulative Generating Capacity	19,976	19,252	19,955	19,260	19,954	19,122	19,627	18,897	19,643	18,816	19,237	18,518	19,237	18,518	19,237
7 Cumulative Purchase Contracts	850	745	842	740	842	740	842	740	839	737	326	319	323	316	212
8 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Cumulative Future Resource Additions															
Peaking/Intermediate	0	0	0	330	0	684	564	1,149	1,149	1,449	1,149	2,841	2,841	2,841	2,841
Base Load	0	0	0	0	0	0	0	0	0	0	0	800	800	1,600	1,600
10 Cumulative Production Capacity	20,826	19,997	20,797	20,330	20,796	20,546	21,033	20,786	21,631	21,002	20,712	22,478	23,201	23,275	23,890
Reserves w/o DSM															
11 Generating Reserves	5,401	2,621	4,982	2,412	4,862	2,310	5,155	2,443	5,630	2,367	3,776	2,789	6,082	3,249	6,589
12 % Reserve Margin	35.0%	15.1%	31.5%	13.5%	30.5%	12.7%	32.5%	13.3%	35.2%	12.7%	22.3%	14.2%	35.5%	16.2%	38.1%
13 % Capacity Margin	25.9%	13.1%	24.0%	11.9%	23.4%	11.2%	24.5%	11.8%	26.0%	11.3%	18.2%	12.4%	26.2%	14.0%	27.6%
DSM															
14 Cumulative DSM Capacity	395	766	387	776	392	792	401	821	417	808	411	794	405	780	397
Existing DSM Capacity	395	766	387	751	380	737	374	721	367	708	361	694	355	680	347
Potential New DSM Capacity	0	0	0	25	12	55	27	100	50	100	50	100	50	100	50
15 Cumulative Equivalent Capacity	21,221	20,763	21,184	21,106	21,188	21,338	21,434	21,607	22,048	21,810	21,123	23,272	23,606	24,055	24,287
Reserves w/DSM															
16 Equivalent Reserves	5,796	3,387	5,369	3,188	5,254	3,102	5,556	3,264	6,047	3,175	4,187	3,583	6,487	4,029	6,986
17 % Reserve Margin	37.6%	19.5%	34.0%	17.8%	33.0%	17.0%	35.0%	17.8%	37.8%	17.0%	24.7%	18.2%	37.9%	20.1%	40.4%
18 % Capacity Margin	27.3%	16.3%	25.3%	15.1%	24.8%	14.5%	25.9%	15.1%	27.4%	14.6%	19.8%	15.4%	27.5%	16.8%	28.8%
Sales (BPM)															
19 Equivalent Sales	127	127	127	127											
Equivalent Reserves	5663	3254	5236	3055	5254	3102	5556	3264	6047	3175	4187	3583	6487	4029	6986
% Reserve Margin	36.5%	18.6%	33.0%	17.0%	33.0%	17.0%	35.0%	17.8%	37.8%	17.0%	24.7%	18.2%	37.9%	20.1%	40.4%
% Capacity Margin	26.7%	15.7%	24.7%	14.5%	24.8%	14.5%	25.9%	15.1%	27.4%	14.6%	19.8%	15.4%	27.5%	16.8%	28.8%

Seasonal Projections of Load, Capacity, and Reserves

W = WINTER, S = SUMMER	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	2013	13/14	2014	14/15	2015	15/16	2016	16/17	2017	17/18	2018	18/19	2019	19/20	2020
Forecast															
1 Duke System Peak	20,393	17,497	20,727	17,602	21,062	17,758	21,413	17,957	21,771	18,116	22,140	18,273	22,505	18,381	22,870
Cumulative System Capacity															
2 Generating Capacity	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518
3 Capacity Additions	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4 Capacity Derates	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5 Capacity Retirements	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6 Cumulative Generating Capacity	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518	19,237	18,518
7 Cumulative Purchase Contracts	205	117	117	72	72	72	72	72	72	72	72	72	72	72	72
8 Cumulative Sales Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Cumulative Future Resource Additions															
Peaking/Intermediate	2,841	2,841	3,405	3,405	3,969	3,969	3,969	3,969	3,405	3,405	3,405	3,405	3,405	3,405	3,975
Base Load	1,600	1,600	1,600	1,600	1,600	1,600	2,717	2,717	3,834	3,834	3,834	3,834	3,834	3,834	3,834
10 Cumulative Production Capacity	23,164	23,795	23,640	24,314	24,159	24,878	25,276	25,995	25,829	26,548	25,829	26,548	25,829	26,548	26,399
Reserves w/o DSM															
11 Generating Reserves	2,771	6,298	2,913	6,712	3,097	7,120	3,863	8,038	4,058	8,432	3,689	8,275	3,324	8,167	3,529
12 % Reserve Margin	13.6%	36.0%	14.1%	38.1%	14.7%	40.1%	18.0%	44.8%	18.6%	46.5%	16.7%	45.3%	14.8%	44.4%	15.4%
13 % Capacity Margin	12.0%	26.5%	12.3%	27.6%	12.8%	28.6%	15.3%	30.9%	15.7%	31.8%	14.3%	31.2%	12.9%	30.8%	13.4%
DSM															
14 Cumulative DSM Capacity	768	398	763	399	759	399	755	400	752	400	747	402	749	404	751
Existing DSM Capacity	668	348	663	349	659	349	655	350	652	350	647	352	649	354	651
Potential New DSM Capacity	100	50	100	50	100	50	100	50	100	50	100	50	100	50	100
15 Cumulative Equivalent Capacity	23,932	24,193	24,403	24,713	24,918	25,277	26,031	26,395	26,581	26,948	26,576	26,950	26,578	26,952	27,150
Reserves w/DSM															
16 Equivalent Reserves	3,539	6,696	3,676	7,111	3,856	7,519	4,618	8,438	4,810	8,832	4,436	8,677	4,073	8,571	4,280
17 % Reserve Margin	17.4%	38.3%	17.7%	40.4%	18.3%	42.3%	21.6%	47.0%	22.1%	48.8%	20.0%	47.5%	18.1%	46.6%	18.7%
18 % Capacity Margin	14.8%	27.7%	15.1%	28.8%	15.5%	29.7%	17.7%	32.0%	18.1%	32.8%	16.7%	32.2%	15.3%	31.8%	15.8%
Sales (BPM)															
19 Equivalent Sales															
Equivalent Reserves	3539	6696	3676	7111	3856	7519	4618	8438	4810	8832	4436	8677	4073	8571	4280
% Reserve Margin	17.4%	38.3%	17.7%	40.4%	18.3%	42.3%	21.6%	47.0%	22.1%	48.8%	20.0%	47.5%	18.1%	46.6%	18.7%
% Capacity Margin	14.8%	27.7%	15.1%	28.8%	15.5%	29.7%	17.7%	32.0%	18.1%	32.8%	16.7%	32.2%	15.3%	31.8%	15.8%

ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLE

The following notes are numbered to match the line numbers on the SEASONAL PROJECTIONS OF LOAD, CAPACITY, AND RESERVES table. All values are MW except where shown as a Percent.

1. Planning is done for the peak demand for the Duke System including Nantahala. Nantahala became a division of Duke Power August 3, 1998.

2. Generating Capacity must be online by June 1 to be included in the available capacity for the summer peak of that year. Capacity must be online by Dec 1 to be included in the available capacity for the winter peak of that year. Includes 103 MW Nantahala hydro capacity, and total capacity for Catawba Nuclear Station less 832 MW to account for NCMPA1 firm capacity sale to Southern Energy Company.
   Also, on January 1, 2006, Generating Capacity reflects a 277 MW reduction to account for PMPA termination of their interconnection agreement with Duke Power.
   Because the Lee CTs serve as a redundant safe-shutdown facility for Oconee Nuclear Station and are required by the NRC for operation of Oconee, the retirement of the existing CTs at Lee in 2006 will coincide with the addition of new CTs at Lee also in 2006 of 86 MW.

3. Capacity Additions reflect an estimated 2 MW Marshall unit double flow IP rotor upgrade and 100 MW capacity uprate at the Jocassee pumped storage facility from increased efficiency from the new runners.

4. The expected Capacity Derates reflect the impact of parasitic loads from planned scrubber additions to various Duke fossil generating units. The units, in order of time sequence on the LCR table is Marshall 1 - 4, Belews Creek 1 & 2, Allen 1 - 3, Cliffside 5, and Allen 4 & 5.

5. The 120 MW capacity retirement in 2010 represents the projected retirement date for all CTs at Riverbend.
   The 88 MW capacity retirement in 2008 represents the projected retirement date for 4 CT's at Buzzard Roost(Wst).
   The 93 MW capacity retirement in 2010 represents the projected retirement date for the existing CTs at Buck.
   The 108 MW capacity retirement in 2010 represents the projected retirement date for 6 CT's at Buzzard Roost(GE).
   The 85 MW capacity retirement in 2010 represents the projected retirement date for CTs at Dan River.
   Duke has an operating lease for the 7 MW Buzzard Roost Hydro Unit which expires 6/30/2006.
   On May 23, 2000, the NRC issued to Duke a renewed facility operating license for its three nuclear units at Oconee. Duke now has the option to operate its Oconee units for up to 20 years following the year 2013. Duke will evaluate on an ongoing basis the viability of operating past the year 2013. With respect to planning purposes, the Oconee capacity is still in the plan.
   The Hydro facilities for which Duke has submitted an application to FERC for licence renewal are assumed to continue operation through the planning horizon.
   All retirement dates are subject to review on an ongoing basis.

7. Cumulative Purchase Contracts have several components:

   A. Effective January 1, 2001, the SEPA allocation was reduced to 94 MW. This reflects self scheduling by Seneca, Greenwood, Saluda River, NCEMC, and NCMPA1. The 94 MW reflects allocations for PMPA and Schedule 10A customers who continue to be served by Duke.
   B. Piedmont Municipal Power Agency has given notice that it will be solely responsible for total load requirements beginning January 1, 2006. This reduces the SEPA allocation to 18 MW in 2006, which is attributed to Schedule 10A customers who continue to be served by Duke.
   C. Purchased capacity from PURPA Qualifying Facilities includes the 88 MW Cherokee County Cogeneration Partners contract which began in June 1998 and expires June 2013 and miscellaneous other QF projects totaling 22 MW.
   D. Purchase of 151 MW from Rowan County Power, LLC, Unit 2 began June 1, 2001 and expires December 31, 2005.
   E. Purchase of 152 MW from Rowan County Power, LLC, Unit 1 began June 1, 2002 and expires May 31, 2007.
   F. Purchase of 153 MW from Rowan County Power, LLC, Unit 3 began June 1, 2004 and expires May 31, 2008.
   G. Purchase of 153 MW from Progress Ventures, Inc. Rowan Unit 2 begins January 1, 2006 and expires December 31, 2010.
   H. Purchase of 153 MW from Progress Ventures, Inc. Rowan Unit 1 begins June 1, 2007 and expires December 31, 2010.
   I. Purchase of 153 MW from Progress Ventures, Inc. Rowan Unit 3 begins June 1, 2008 and expires December 31, 2010.
   J. Purchase of 160 MW from Dynegy/Rockingham unit begins January 1, 2006 and expires December 31, 2010.

9. Cumulative Future Resource Needs represent a combination of new capacity resources , short/long-term capacity purchases from the wholesale market, capacity purchase options, or capability increases which are being considered.
   Neither the date of operation, the type of resource, nor the size is firm. All Future Resource Needs are uncommitted and represent capacity required to maintain the target planning reserve margin.

12. Reserve margin is shown for reference only.
    Reserve Margin = (Cumulative Capacity-System Peak Demand)/System Peak Demand

13. Capacity margin is the industry standard term. A 14.6 percent capacity margin is equivalent to a 17.0 percent reserve margin.
    Capacity Margin = (Cumulative Capacity - System Peak Demand)/Cumulative Capacity

14. Cumulative Demand Side Management capacity represents the demand-side management contribution toward meeting the load. The programs reflected in these numbers include interruptible Demand Side Management programs designed to be activated during capacity problem situations.

APPENDIX F: GENERATING UNITS UNDER CONSTRUCTION OR PLANNED

A list of generating units under construction or planned at plant locations for which property has been acquired, for which certificates have been received, or for which applications have been filed include:

Duke Power continues to assess the viability of all of its generating units in relation to new generation and purchased power. The Company filed preliminary information with the NCUC for a Certificate of Public Convenience and Necessity (CPCN) for a 600 MW combined cycle facility at the Buck Steam Station in Salisbury, N.C. in May 2005. Also, during May 2005, the Company filed preliminary information with the NCUC for a CPCN for up to 1600 MWs of pulverized coal generation at the Cliffside Steam Station in Cliffside, N.C.

APPENDIX G: PROPOSED GENERATING UNITS AT LOCATIONS NOT KNOWN

A list of proposed generating units at locations not known with capacity, plant type, and date of operation included to the extent known:

Line 9 of the Seasonal Projections of Load, Capacity, and Reserves for Duke Power identifies cumulative future resource additions needed to reliably meet customer load. Resource additions may be a combination of short/long-term capacity purchases from the wholesale market, capacity purchase options, and building or contracting of new generation. In the preliminary filings with the NCUC for the CPCNs at Buck and Cliffside Steam Stations, the Company noted its intent to also pursue CPCNs for coal and combined cycle capacity at sites in South Carolina. However, no decision has been made with regard to pursuit of South Carolina CPCNs at the time of the filing of this Plan.

APPENDIX H: TRANSMISSION LINES AND OTHER ASSOCIATED FACILITIES PLANNED OR UNDER CONSTRUCTION

The following table identifies significant planned construction projects and those currently under construction in Duke Power's transmission system.

PROJECT	VOLTAGE	LOCATION OF CONNECTION STATION	LINE CAPACITY	SCHEDULED OPERATION
Draytonville Line	230 kV	Ripp Switching Station to Riverview Switching Station	Double circuit upgrade to bundled 795 conductor – 819 MVA	June 1, 2006
Kelsey Creek Line	230 kV	Tiger Tie to Pacolet Tie	Add second circuit to existing tower line – 437 MVA	June 1, 2006
Dutchover Line	230 kV	Riverbend Steam Station to Lincoln Combustion Turbine Station	Reconfigure Riverbend – McGuire (Schoonover) Line and McGuire – Lincoln Combustion Turbine (Dutchman) Line to bypass McGuire – 598 MVA	Dec. 1, 2006

In addition, NCUC Rule R8-62(p) requires the following information.

1. For existing lines, the information required on FERC Form 1, pages 422, 423, 424 and 425: (Please see Appendix K for Duke Power's current FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 424 and 425.)

2. For lines under construction:
   - Commission docket number
   - Location of end point(s)
   - Length
   - Range of right-of-way width
   - Range of tower heights
   - Number of circuits
   - Operating voltage
   - Design capacity
   - Date construction started
   - Projected in-service date.

Duke Power has no lines rated at 161 KV or greater under construction.

3. For all other proposed lines, as the information becomes available:
   - County location of end point(s)
   - Approximate length
   - Typical right-of-way width for proposed type of line
   - Typical tower height for proposed type of line
   - Number of circuits
   - Operating voltage
   - Design capacity
   - Estimated date for starting construction
   - Estimated in-service date.

Duke Power has no proposed transmission lines rated at 161 kV or greater.

APPENDIX I: GENERATION AND ASSOCIATED TRANSMISSION FACILITIES SUBJECT TO CONSTRUCTION DELAYS

A list of any generation and associated transmission facilities under construction which have delays of over six months in the previously reported in-service dates and the major causes of such delays. Upon request from the Commission Staff, the reporting utility shall supply a statement of the economic impact of such delays:

There are no delays over six months in the stated in-service dates.

APPENDIX J: DEMAND-SIDE AND SUPPLY-SIDE OPTIONS REFERENCED IN THE PLAN.

Supply-Side Options

Supply-side options considered in the Annual Plan are subjected to an economic screening process to determine the most cost-effective technologies. Conventional, demonstrated and emerging technologies must pass a cost screen, a commercial availability screen, and a technical feasibility screen to be considered for further evaluation.

The data for each technology is based on research by Duke Power's generation team, the Electric Power Research Institute (EPRI) Technology Assessment Guide, and fuel and operating costs developed by internal and other sources. The EPRI information is not site-specific but reflects costs and operating parameters that are adjusted for installation in the Southeast.

Supply-side technologies evaluated were:

Conventional Technologies (technologies in common use):

- 564 MW Combustion Turbine
- 585 MW Combined Cycle
- 400 MW Supercritical Conventional Fossil
- 600 MW Supercritical Conventional Fossil
- 800 MW Supercritical Conventional Fossil
- 1200 MW Supercritical Conventional Fossil
- 1600 MW Supercritical Conventional Fossil
- 400 MW Circulating Fluidized Bed Coal, Atmospheric
- 1050 MW Pumped Storage
- 75 MW Wind Power

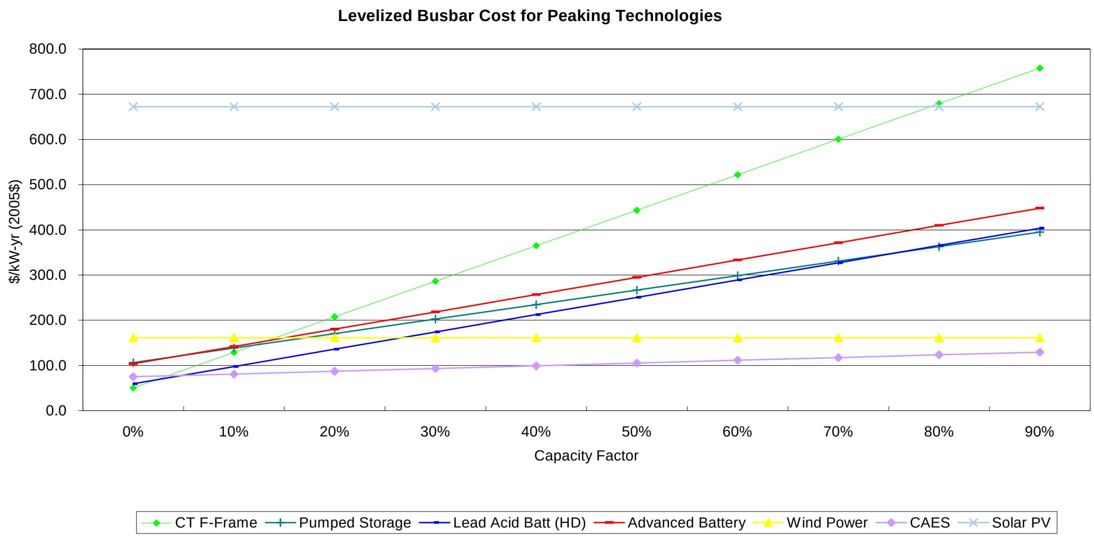
Demonstrated Technologies (technologies with limited acceptance and not in widespread use):

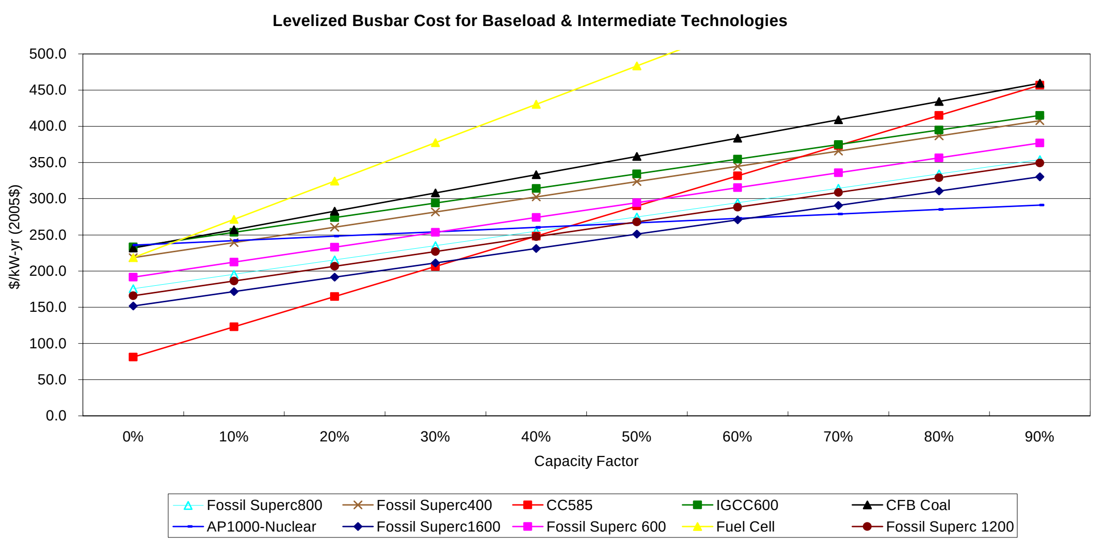
- 2234 MW Nuclear AP1000
- 20 MW Lead Acid Battery
- 18 MW Advanced Battery
- 350 MW Compressed Air Energy Storage
- 600 MW Integrated Gasification Combined Cycle
- 1 MW Molten Carbonate Fuel Cell

Emerging Technologies (technologies in the developmental stage or that have not been used in the electric utility industry):

- 5 MW Solar Photovoltaic

The following Levelized Busbar Cost charts provide an economic comparison of all the technologies considered.





Technologies which are commercially available, cost-effective and technically feasible for use in the Carolinas were passed on to the quantitative analysis phase for further evaluation. The following points explain why various technologies were eliminated from further consideration.

- Although Circulating Fluidized Bed Coal is a conventional technology that is technically feasible, it is one of the highest-cost generation technologies in the baseload duty cycle.

- Pumped Storage is a commercially available and technically feasible technology. However, Duke Power currently has more than 2,000 MW of pumped storage capacity in its generation portfolio. Pumped storage is designed to complement baseload generation and could be considered further in conjunction with future baseload additions.

- Wind Power is not a reliably dispatchable resource, limiting its competitiveness against peaking duty cycle technologies. Also, sufficient wind energy in the Duke Power service territory is found only in the ridge-lines of the North Carolina mountains which is currently under development restrictions.

- Advanced Battery technology is applicable for emergency operations (short-term duty cycles) of three hours or less. The technology is also in the pilot phase, and not commercially available.

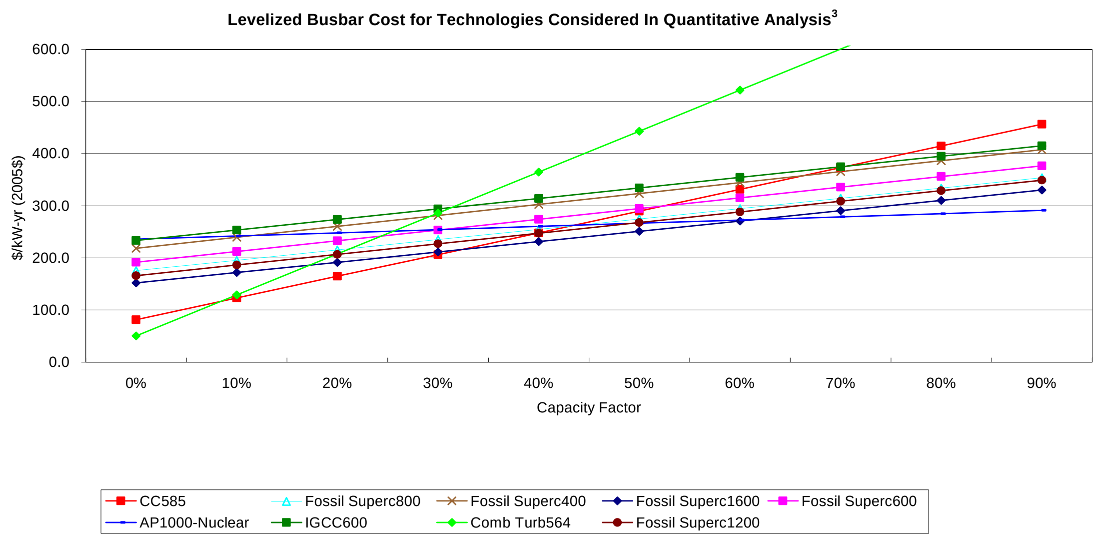
- Lead Acid Battery technology is not commercially available. As it is applicable only for short-term emergency operation (one hour or less), it would not meet the general requirements for peaking duty cycle.

- Compressed Air Energy Storage is not a commercially available technology, and there are no viable sites in Duke Power's service territory to support it.

- Molten Carbonate Fuel Cell technology is currently undergoing developmental testing at several demonstration plants. It is not commercially available and is one of the higher-cost baseload duty cycle technologies.

- Solar Photovoltaic technology is still an evolving technology. It is not dispatchable without energy storage and is better suited for remote niche applications that require watt-to-kilowatt capability. In addition, large-scale photovoltaic applications are not competitive with peaking and intermediate duty cycle technologies.

The chart on the following page shows the technologies which are commercially available, cost-effective and technically feasible for use in the Carolinas. Combustion turbine is the most cost-effective technology for peaking duty cycles, combined cycle for intermediate duty cycles and an assortment of combined cycle, coal and nuclear for baseload duty cycles. The pricing for combined cycle depends on the price of natural gas. Duke Power will continue to monitor the cost variation between coal and nuclear technologies versus combined cycle as the price of natural gas changes.



These technologies were selected for the quantitative analysis:

- 564 MW Combustion Turbine
- 585 MW Combined Cycle
- 400 MW Supercritical Conventional Fossil (Superc)
- 600 MW Superc
- 800 MW Superc
- 1200 MW Superc
- 1600 MW Superc
- 600 MW IGCC
- 2,234 MW Nuclear

[3] While levelized busbar costs provide a reasonable basis for initial screening of technologies, busbar cost information has limitations. In isolation, busbar cost information has limited applicability in decision-making because it is highly dependent on the circumstances being considered. A complete analysis of feasible technologies must include consideration of the interdependence of the technologies and Duke Power's existing generation portfolio.

Demand-Side Management

Duke Power is currently developing a DSM strategy that includes a more detailed analysis of the size and character of potential programs. This strategy will focus on identifying and implementing an appropriate amount of additional DSM. The 2005 Annual Plan includes 100 MW of additional demand-response program capability. This amount and the potential DSM programs which could be implemented may change based on further analysis and the results of the DSM strategy analysis underway.

Below is a summary of potential DSM programs considered in the planning process.

Direct Load Control

Direct load control could be designed to target residential or commercial class customers and dispatched to a geographic region or systemwide. Potential load sources that could be directly controlled include water heating, air conditioning and swimming pool pumps. Estimated load impacts are between .5 kW and 1.6 kW per residential customer and 2.5 kW per commercial customer.

Interruptible Service

Interruptible service could be designed to target large commercial or industrial customers and dispatched to a geographic region or systemwide. This program was assumed to have a load impact of approximately 2.06 MW per customer.

Standby Generation

Standby generation could be designed to target commercial or industrial customers and could be dispatched specifically to a geographic region or systemwide. This program was assumed to have a load impact of approximately 258 kW per customer.

Energy Efficiency Programs

The DSM energy efficiency analysis was intended to be indicative of the level of opportunity available to Duke Power, rather than as a precise estimate of program costs and benefits.

Projected New DSM Demand Response Program Details				
Expected Total MW Reduction	Expected Total MW Reduction (2006)	Expected Total MW Reduction (2007)	Expected Total MW Reduction (2008)	Expected Total MW Reduction (2009)
100	0	25	55	100

Projected New DSM Energy Efficiency Program Details	
Category (all customer types)	Expected Total Annual MWh Reduction
EE	715,927

APPENDIX K: NON-UTILITY GENERATION/CUSTOMER-OWNED GENERATION/STAND-BY GENERATION:

In NCUC Order dated Feb. 20, 2003, in Docket No. E-100, Sub 97, the NCUC required North Carolina utilities to provide a separate list of all non-utility electric generating facilities in the North Carolina portion of their control areas, including customer-owned and standby generating facilities, to the extent possible. Duke Power's response to that Order was based on the best available information, and the Company has not attempted to independently validate it. In addition, some of that information duplicates data that Duke Power supplies elsewhere in this Annual Plan.

CUSTOMER-OWNED STANDBY GENERATION				
CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Belmont	NC	350	Unknown	Yes[1]
Belmont	NC	350	Unknown	Yes[1]
Belmont	NC	500	Unknown	Yes[1]
Bessemer City	NC	440	Unknown	Yes[1]
Burlington	NC	550	Unknown	Yes[1]
Burlington	NC	600	Unknown	Yes[1]
Burlington	NC	650	Unknown	Yes[1]
Burlington	NC	225	Unknown	Yes[1]
Burlington	NC	200	Unknown	Yes[1]
Burlington	NC	1,150	Unknown	Yes[1]
Butner	NC	750	Unknown	Yes[1]
Butner	NC	1,250	Unknown	Yes[1]
Carrboro	NC	1,135	Unknown	Yes[1]
Carrboro	NC	500	Unknown	Yes[1]
Carrboro	NC	2,000	Unknown	Yes[1]
Chapel Hill	NC	500	Unknown	Yes[1]
Charlotte	NC	1,750	Unknown	Yes[1]
Charlotte	NC	500	Unknown	Yes[1]
Charlotte	NC	1,000	Unknown	Yes[1]
Charlotte	NC	1,250	Unknown	Yes[1]
Charlotte	NC	1,135	Unknown	Yes[1]
Charlotte	NC	1,135	Unknown	Yes[1]
Charlotte	NC	1,500	Unknown	Yes[1]
Charlotte	NC	219	Unknown	Yes[1]
Charlotte	NC	10,000	Unknown	Yes[1]
Charlotte	NC	200	Unknown	Yes[1]
Charlotte	NC	2,200	Unknown	Yes[1]
Charlotte	NC	700	Unknown	Yes[1]
Charlotte	NC	5,600	Unknown	Yes[1]
Charlotte	NC	4,000	Unknown	Yes[1]
Concord	NC	680	Unknown	Yes[1]
Danbury	NC	400	Unknown	Yes[1]
Durham	NC	1,300	Unknown	Yes[1]
Durham	NC	2,500	Unknown	Yes[1]
Durham	NC	3,200	Unknown	Yes[1]
Durham	NC	1,600	Unknown	Yes[1]
Durham	NC	1,400	Unknown	Yes[1]
Durham	NC	1,500	Unknown	Yes[1]
Durham	NC	2,250	Unknown	Yes[1]
Durham	NC	7,000	Unknown	Yes[1]
Durham	NC	1,900	Unknown	Yes[1]
Durham	NC	1,750	Unknown	Yes[1]
Durham	NC	4,525	Unknown	Yes[1]
Durham	NC	4,500	Unknown	Yes[1]
Durham	NC	6,400	Unknown	Yes[1]

CUSTOMER-OWNED STANDBY GENERATION				
CITY	STATE	NAMEPLATE KW	PRIMARY FUEL TYPE	PART OF TOTAL SUPPLY RESOURCES
Durham	NC	625	Unknown	Yes[1]
Durham	NC	2,000	Unknown	Yes[1]
Eden	NC	1,700	Unknown	Yes[1]
Elkin	NC	400	Unknown	Yes[1]
Elkin	NC	500	Unknown	Yes[1]
Gastonia	NC	910	Unknown	Yes[1]
Gastonia	NC	680	Unknown	Yes[1]
Gastonia	NC	12,500	Unknown	Yes[1]
Graham	NC	800	Unknown	Yes[1]
Greensboro	NC	1,350	Unknown	Yes[1]
Greensboro	NC	125	Unknown	Yes[1]
Greensboro	NC	1,000	Unknown	Yes[1]
Greensboro	NC	1,500	Unknown	Yes[1]
Greensboro	NC	2,000	Unknown	Yes[1]
Greensboro	NC	750	Unknown	Yes[1]
Greensboro	NC	1,280	Unknown	Yes[1]
Greensboro	NC	700	Unknown	Yes[1]
Hendersonville	NC	500	Unknown	Yes[1]
Hendersonville	NC	1,000	Unknown	Yes[1]
Hendersonville	NC	1,000	Unknown	Yes[1]
Hickory	NC	1,500	Unknown	Yes[1]
Hickory	NC	750	Unknown	Yes[1]
Hickory	NC	1,000	Unknown	Yes[1]
Hickory	NC	1,500	Unknown	Yes[1]
Hickory	NC	1,040	Unknown	Yes[1]
Hickory	NC	500	Unknown	Yes[1]
Huntersville	NC	2,950	Unknown	Yes[1]
Huntersville	NC	775	Unknown	Yes[1]
Indian Trail	NC	900	Unknown	Yes[1]
King	NC	800	Unknown	Yes[1]
Lexington	NC	750	Unknown	Yes[1]
Lexington	NC	2,950	Unknown	Yes[1]
Lincolnton	NC	300	Unknown	Yes[1]
Marion	NC	650	Unknown	Yes[1]
Matthews	NC	1,450	Unknown	Yes[1]
Mebane	NC	400	Unknown	Yes[1]
Midland	NC	4,000	Unknown	Yes[1]
Midland	NC	6,000	Unknown	Yes[1]
Monroe	NC	400	Unknown	Yes[1]
Mooresville	NC	750	Unknown	Yes[1]
Morganton	NC	200	Unknown	Yes[1]
Mt. Airy	NC	600	Unknown	Yes[1]
Mt. Airy	NC	750	Unknown	Yes[1]
Mt. Holly	NC	210	Unknown	Yes[1]
N. Wilkesboro	NC	600	Unknown	Yes[1]

CUSTOMER-OWNED STANDBY GENERATION				
CITY	**STATE**	**NAMEPLATE KW**	**PRIMARY FUEL TYPE**	**PART OF TOTAL SUPPLY RESOURCES**
N. Wilkesboro	NC	155	Unknown	Yes[1]
North Wilkesboro	NC	1,250	Unknown	Yes[1]
Pfafftown	NC	4,000	Unknown	Yes[1]
Reidsville	NC	750	Unknown	Yes[1]
Research Triangle	NC	750	Unknown	Yes[1]
Research Triangle	NC	1,000	Unknown	Yes[1]
Research Triangle	NC	350	Unknown	Yes[1]
Research Triangle	NC	750	Unknown	Yes[1]
Rural Hall	NC	1,050	Unknown	Yes[1]
Rutherfordton	NC	800	Unknown	Yes[1]
Salisbury	NC	1,500	Unknown	Yes[1]
Salisbury	NC	1,500	Unknown	Yes[1]
Shelby	NC	4,480	Unknown	Yes[1]
Valdese	NC	600	Unknown	Yes[1]
Valdese	NC	800	Unknown	Yes[1]
Welcome	NC	300	Unknown	Yes[1]
Winston	NC	750	Unknown	Yes[1]
Winston Salem	NC	1,800	Unknown	Yes[1]
Winston Salem	NC	3,360	Unknown	Yes[1]
Winston Salem	NC	1,250	Unknown	Yes[1]
Winston Salem	NC	3,000	Unknown	Yes[1]
Winston Salem	NC	2,000	Unknown	Yes[1]
Winston Salem	NC	3,000	Unknown	Yes[1]
Winston-Salem	NC	500	Unknown	Yes[1]
Winston-Salem	NC	3,200	Unknown	Yes[1]
Winston-Salem	NC	400	Unknown	Yes[1]
Winston-Salem	NC	3,750	Unknown	Yes[1]
Yadkinville	NC	500	Unknown	Yes[1]
Yadkinville	NC	1,200	Unknown	Yes[1]
Anderson	SC	2,250	Unknown	Yes[1]
Anderson	SC	1,500	Unknown	Yes[1]
Bullock Creek	SC	275	Unknown	Yes[1]
Clinton	SC	447	Unknown	Yes[1]
Clover	SC	75	Unknown	Yes[1]
Duncan	SC	600	Unknown	Yes[1]
Fort Mill	SC	1,600	Unknown	Yes[1]
Gaffney	SC	1,200	Unknown	Yes[1]
Greenville	SC	3,650	Unknown	Yes[1]
Greenville	SC	300	Unknown	Yes[1]
Greenville	SC	500	Unknown	Yes[1]
Greenwood	SC	2,400	Unknown	Yes[1]
Greenwood	SC	600	Unknown	Yes[1]
Greer	SC	125	Unknown	Yes[1]
Greer	SC	1,250	Unknown	Yes[1]
Inman	SC	165	Unknown	Yes[1]

CUSTOMER-OWNED STANDBY GENERATION				
CITY	**STATE**	**NAMEPLATE KW**	**PRIMARY FUEL TYPE**	**PART OF TOTAL SUPPLY RESOURCES**
Kershaw	SC	165	Unknown	Yes[1]
Kershaw	SC	1,500	Unknown	Yes[1]
Lancaster	SC	1,500	Unknown	Yes[1]
Lancaster	SC	300	Unknown	Yes[1]
Lyman	SC	1,000	Unknown	Yes[1]
Mt. Holly	SC	265	Unknown	Yes[1]
Simpsonville	SC	900	Unknown	Yes[1]
Simpsonville	SC	458	Unknown	Yes[1]
Spartanburg	SC	600	Unknown	Yes[1]
Spartanburg	SC	450	Unknown	Yes[1]
Spartanburg	SC	2,900	Unknown	Yes[1]
Spartanburg	SC	650	Unknown	Yes[1]
Spartanburg	SC	1,600	Unknown	Yes[1]
Taylor	SC	350	Unknown	Yes[1]
Van Wyck	SC	450	Unknown	Yes[1]
Van Wyck	SC	365	Unknown	Yes[1]
Walhalla	SC	350	Unknown	Yes[1]

Note 1: Nameplate rating is typically greater than maximum net dependable capability that generator contributes to Duke resources

PURPA QUALIFYING FACILITIES (SELLING POWER TO DUKE)					
NAME	**CITY**	**STATE**	**NAMEPLATE KW**	**PRIMARY FUEL TYPE**	**PART OF TOTAL SUPPLY RESOURCES**
Barbara Ann Evans - Caroleen Mills [2]	Caroleen	NC	324	Hydro	Yes[1]
Bullock Development Corp - Stice Shoals Hydro	Shelby	NC	600	Hydro	Yes[1]
Catawba County - Blackburn Landfill	Newton	NC	4,000	Landfill Gas	Yes[1]
Ecusta Business Development Center	Brevard	NC	5,000	Coal	Yes[1]
Haw River Hydro Co	Saxapahaw	NC	1,500	Hydro	Yes[1]
Mayo Hydropower, LLC - Avalon Dam	Mayodan	NC	1,275	Hydro	Yes[1]
Mayo Hydropower, LLC - Mayo Dam	Mayodan	NC	950	Hydro	Yes[1]
Mill Shoals Hydro Co - High Shoals Hydro	High Shoals	NC	1,800	Hydro	Yes[1]
Northbrook Carolina Hydro - Spencer Mtn Hydro	Spencer Mtn	NC	640	Hydro	Yes[1]
Northbrook Carolina Hydro - Turner Shoals Hydro	Mill Springs	NC	5,500	Hydro	Yes[1]
Salem Energy Systems, LLC	Winston-Salem	NC	4,270	Landfill Gas	Yes[1]
South Yadkin Power, Inc	Cooleemee	NC	1,400	Hydro	Yes[1]
Spray Cotton Mills	Eden	NC	500	Hydro	Yes[1]
Steve Mason Enterprises-Harden Hydro	Hardins	NC	820	Hydro	Yes[1]
Steve Mason Enterprises-Long Shoals Hydro	Long Shoals	NC	900	Hydro	Yes[1]
Town of Lake Lure	Lake Lure	NC	3,600	Hydro	Yes[1]
Aquenergy Systems Inc	Piedmont	SC	1,050	Hydro	Yes[1]
Aquenergy Systems Inc	Ware Shoals	SC	6,300	Hydro	Yes[1]
Aquenergy Systems Inc	Cateechee	SC	450	Hydro	Yes[1]
Aquenergy Systems Inc	Cateechee	SC	440	Hydro	Yes[1]
Cherokee County Cogeneration Partners	Gaffney	SC	100,000	Gas-fired Cogen	Yes[1]
Converse Energy Inc	Converse	SC	1,250	Hydro	Yes[1]
Daniel Nelson Evans - Whitney Hydro	Spartanburg	SC	240	Hydro	Yes[1]
Northbrook Carolina Hydro - Boyds Mill Hydro	Ware Shoals	SC	1,500	Hydro	Yes[1]
Northbrook Carolina Hydro - Hollidays Bridge Hydro	Anderson	SC	3,500	Hydro	Yes[1]
Northbrook Carolina Hydro - Saluda Hydro	Greenville	SC	2,400	Hydro	Yes[1]
Pacolet River Power Co	Clifton	SC	800	Hydro	Yes[1]
Pelzer Hydro Co - Upper Hydro	Pelzer	SC	2,020	Hydro	Yes[1]
Pelzer Hydro Co - Lower Hydro	Williamston	SC	3,300	Hydro	Yes[1]
RCR Enterprises Inc	Welcome	NC	-	Engine Dynomometer	No[1]

Note 1: Nameplate rating generally exceeds the contract capacity negotiated for Duke Power
Note 2: Formerly Clearwater Hydro

MERCHANT GENERATORS					
NAME	**CITY**	**STATE**	**NAMEPLATE KW**	**PRIMARY FUEL TYPE**	**PART OF TOTAL SUPPLY RESOURCES**
Dynegy Power Marketing, Inc.	Bethany	NC	810,000	Natural gas	Yes[1]
Progress Ventures, Inc.	Salisbury	NC	500,000	Natural gas	Yes[1]
Broad River Energy Center, LLC	Gaffney	SC	875,000	Natural gas	No

Note 1: Nameplate rating generally exceeds the contract capacity negotiated for Duke Power

CUSTOMER-OWNED SELF-GENERATION				
COUNTY	**STATE**	**NAMEPLATE KW**	**PRIMARY FUEL TYPE**	**PART OF TOTAL SUPPLY RESOURCES**
Alamance	NC	250	Hydro	No[1]
Burke	NC	800	Diesel	No[1]
Cabarrus	NC	21,000	Diesel	No[1]
Catawba	NC	250	Coal, Wood Cogen	No[1]
Catawba	NC	8,050	Diesel	No[1]
Cleveland	NC	9,525	Diesel	No[1]
Cleveland	NC	2,000	Diesel	No[1]
Forsyth	NC	8,400	Coal, Wood Cogen	No[1]
Gaston	NC	1,056	Hydro	No[1]
Gaston	NC	11,500	Coal Cogen	No[1]
Gaston	NC	3,200	Diesel	No[1]
Guilford	NC	2,000	Diesel	No[1]
Guilford	NC	900	Diesel	No[1]
Guilford	NC	2,000	Diesel	No[1]
Iredell	NC	1,050	Diesel	No[1]
Orange	NC	28,000	Coal Cogen	No[1]
Rockingham	NC	5,480	Coal Cogen	No[1]
Rutherford	NC	1,625	Hydro	No[1]
Rutherford	NC	4,800	Diesel	No[1]
Rutherford	NC	4,800	Diesel	No[1]
Rutherford	NC	750	Diesel	No[1]
Rutherford	NC	1,000	Diesel	No[1]
Rutherford	NC	350	Diesel	No[1]
Surry	NC	2,500	Unknown	No[1]
Union	NC	12,500	Diesel	No[1]
Union	NC	7,400	Diesel	No[1]
Union	NC	4,950	Diesel	No[1]
Union	NC	4,200	Diesel	No[1]
Union	NC	1,600	Diesel	No[1]
Union	NC	1,600	Diesel	No[1]
Union	NC	1,600	Diesel	No[1]
Abbeville	SC	3,250	Hydro	No[1]
Abbeville	SC	2,865	Diesel	No[1]
Cherokee	SC	8,000	Diesel	No[1]
Cherokee	SC	4,140	Hydro	No[1]
Greenville	SC	5,000	Natural Gas, Landfill Gas	No[1]
Greenville	SC	250	Unknown	No[1]
Greenville	SC	370	Digester Gas	No[1]
Greenville	SC	4,550	Diesel Cogen	No[1]
Lancaster	SC	22,500	Coal Cogen	No[1]
Laurens	SC	2,150	Diesel	No[1]
Laurens	SC	4,000	Diesel	No[1]

CUSTOMER-OWNED SELF-GENERATION				
COUNTY	**STATE**	**NAMEPLATE KW**	**PRIMARY FUEL TYPE**	**PART OF TOTAL SUPPLY RESOURCES**
Oconee	SC	700	Hydro	No[1]
Oconee	SC	2,865	Diesel	No[1]
Pickens	SC	2,865	Diesel	No[1]
Pickens	SC	6,400	Diesel	No[1]
Spartanburg	SC	1,000	Hydro	No[1]
Greenville	SC	2,550	Diesel	No[1]
Union	SC	15,900	Hydro	No[1]
Union	SC	5,730	Diesel	No[1]
York	SC	42,500	Coal, Wood Cogen	No[1]
York	SC	29,000	Coal Cogen	No[1]
York	SC	3,000	Diesel	No[1]
York	SC	2,865	Diesel	No[1]
York	SC	2,865	Diesel	No[1]

Note 1: The Load Forecast in the Annual Plan reflects the impact of these generating resources

UTILITY-OWNED STANDBY GENERATION				
COUNTY	**STATE**	**NAMEPLATE KW**	**PRIMARY FUEL TYPE**	**PART OF TOTAL SUPPLY RESOURCES**
Alamance	NC	275	Diesel	No
Granville	NC	1,750	Diesel	No
Mecklenburg	NC	1,750	Diesel	No
Mecklenburg	NC	1,500	Diesel	No
Mecklenburg	NC	150	Diesel	No
Mecklenburg	NC	200	Diesel	No
Mecklenburg	NC	400	Diesel	No
Mecklenburg	NC	1,000	Diesel	No
Durham	NC	1,750	Diesel	No
Wilkes	NC	2,000	Diesel	No

APPENDIX L: FERC FORM 1 PAGES

Following are Duke Power's 2004 FERC Form 1 pages 422, 423, 422.1, 423.1, 422.2, 423.2, 424 and 425.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1								
2	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.65		1
3	McGuire SW	Antioch Tie	525.00	525.00	Tower	54.35		1
4	McGuire SW	Newport	525.00	525.00	Tower	32.26		1
5	McGuire SW	Woodleaf SW	525.00	525.00	Tower	29.97		1
6	Woodleaf SW	Pleasant Garden Tie	525.00	525.00	Tower	53.09		1
7	Pleasant Garden Tie	Parkwood	525.00	525.00	Tower	49.66		1
8	Newport	Rockingham	525.00	525.00	Tower	48.68		1
9	Oconee	Newport	525.00	525.00	Tower	107.92		1
10	Oconee	Norcross	525.00	525.00	Tower	22.51		1
11	Oconee	Jocassee	525.00	525.00	Tower	20.89		1
12	Jocassee	McGuire	525.00	525.00	Tower	119.88		1
13	Jocassee	Bad Creek	525.00	525.00	Tower	9.24		1
14								
15	Total 525kv Lines					576.10		12
16								
17	Allen	Pacolet - Tiger	230.00	230.00	Tower	80.22		
18	Allen	Beckerdite	230.00	230.00	Tower	79.89		2
19	Allen	Riverbend	230.00	230.00	Tower	12.50		2
20	Allen	Woodlawn	230.00	230.00	Tower	8.13		2
21	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.32		2
22	Beckerdite	Pleasant Garden - Eno	230.00	230.00	Tower	71.26		2
23	Beckerdite	Rural Hall	230.00	230.00	Tower	107.03		2
24	Belews Creek	Sadler tie	230.00	230.00	Tower	26.31		2
25	Catawba	Peacock	230.00	230.00	Tower	14.82		2
26	Central	Anderson	230.00	230.00	Tower	23.13		2
27	Cliffside	Pacolet	230.00	230.00	Tower	23.01		2
28	Cliffside	Shelby	230.00	230.00	Tower	14.12		2
29	East Durham	Parkwood - Eno - Roxboro	230.00	230.00	Tower	33.00		2
30	Eno Tie - East Durham	CP&L	230.00	230.00	Tower	15.80		2
31	Greenville	Shady Grove - Central	230.00	230.00	Tower/Poles	34.01		2
32	Greenville	Shiloh - Pisgah Forest	230.00	230.00	Tower	30.82		2
33	Hartwell	Anderson - Hodges	230.00	230.00	Tower	36.96		2
34	Jocassee Tie	Tuckaseegee	230.00	230.00	Tower	26.63		2
35	Lincoln CT	Longview Tie	230.00	230.00	Tower	31.22		2
36					TOTAL	8,300.84		96

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
2515								11
2515								12
2515								13
2515								14
	20,434,428	97,499,092	117,933,520					15
	20,434,428	97,499,092	117,933,520					16
								17
954 & 1272								18
954								19
954 &1272								20
2156								21
954 & 1272								22
954								23
954 & 2156								24
1272								25
1272								26
954								27
954								28
954								29
1272								30
1272								31
954 & 2515								32
954								33
954 & 2515								34
1272								35
795								
	140,176,763	863,774,892	1,003,951,655	868,069	14,316,261		15,184,330	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Longview	McDowell	230.00	230.00	Tower	31.96		2
2	Marshall	Longview	230.00	230.00	Tower	29.06		2
3	Marshall	Mitchell River	230.00	230.00	Tower	49.49		2
4	Marshall	Winecoff	230.00	230.00	Tower	24.36		2
5	McGuire-Harrisburg-Oakboro	Newport - Catawba	230.00	230.00	Tower	139.44		
6	McGuire SW	Lincoln CT	230.00	230.00	Tower	5.34		2
7	Mitchell	Rural Hall	230.00	230.00	Tower	43.74		2
8	Newport	Parr - Bush River	230.00	230.00	Tower	63.25		1
9	Oconee	Central	230.00	230.00	Tower	17.64		2
10	Oconee	Jocassee - Shiloh - Tiger	230.00	230.00	Tower/Poles	85.54		2
11	Pisgah Forest	Skyland	230.00	230.00	Tower	14.42		2
12	Riverbend	Lakewood (Pinoca)	230.00	230.00	Tower	10.64		2
13	Riverbend	McGuire-Marshall-Beckerdite	230.00	230.00	Tower	79.95		2
14	Riverbend	Shelby-Peach Valley-Tiger	230.00	230.00	Tower	109.40		2
15	Tiger	North Greenville	230.00	230.00	Tower	18.40		2
16								
17	Total 230kv Lines					1,395.81		63
18								
19	Natahala Tie	Marble S. S.	161.00	161.00	Tower	16.85		2
20	Natahala Tie	Robbinsville S.S.	161.00	161.00	Tower	8.33		1
21	Santeetlah Tie	Robbinsville S.S.	161.00	161.00	Tower	11.14		1
22	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Poles	2.52		1
23	Tuckasegee Tie	Webster Tie - West Mill Tie	161.00	161.00	Tower	10.40		1
24	Webster Tie	Nantahala Plant	161.00	161.00	Tower	12.70		1
25	Webster Tie	Lake Emory S.S.	161.00	161.00	Tower	11.93		1
26	West Mill Tie	Lake Emory - Nantahala Tie	161.00	161.00	Poles	6.78		1
27	Tuckasegee Tie	Webster Tie - NPL Portion	161.00	161.00	Tower	1.36		2
28	Dan River	Appalachian	138.00	138.00	Tower/Poles	6.50		1
29	Horsehoe Tie	Skyland CP&L	115.00	115.00	Tower/Poles	7.63		1
30	Saluda Dam	Bush River Tie	110.00	110.00	Tower	11.48		2
31	Clark Hill	Greenwood	110.00	110.00	Wood Poles	35.76		1
32	Tuckaseegee Tie	Thorpe Hydro	161.00	161.00	Tower	1.40		1
33	100kv Lines		100.00	100.00	Tower	2,992.40		
34	100kv Lines		100.00	100.00	Poles	418.81		
35	100kv Lines		100.00	100.00	Underground	1.84		
36					TOTAL	8,300.84		96

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g).
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954								1
1272								2
954								3
1272								4
954 & 1272								5
795								6
954 & 2156								7
954								8
795 & 1272								9
1272 & 2156								10
954								11
795 & 954								12
954 & 1272								13
795 & 954								14
954								15
	39,923,411	201,413,805	241,337,216					16
	39,923,411	201,413,805	241,337,216					17
								18
795								19
636								20
636								21
397.5								22
795								23
795								24
636								25
795								26
795								27
477								28
477 & 1272								29
336								30
398								31
1272								32
								33
								34
								35
	140,176,763	863,774,892	1,003,951,655	868,069	14,316,261		15,184,330	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2004	End of 2004/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1								
2	Total 100-161kv Lines					3,557.83		17
3								
4	66kv Lines		66.00	66.00	Poles	113.88		1
5								
6	Total 66kv Lines					113.88		1
7								
8	44kv Lines		44.00	44.00	Tower	264.85		
9	44kv Lines		44.00	44.00	Poles	2,232.38		
10	44kv Lines		44.00	44.00	Underground	0.73		1
11								
12	Total 44kv Lines					2,497.96		1
13								
14	33kv Lines		33.00	33.00	Poles	5.46		1
15	22 kv Lines		22.00	22.00	Poles	118.46		
16	13kv Lines		13.00	13.00	Poles	35.09		
17	13kv Lines		13.00	13.00	Underground	0.25		1
18								
19	Total 13-33kv Lines					159.26		2
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,300.84		96

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	54,102,210	408,380,298	462,482,508					1
	54,102,210	408,380,298	462,482,508					2
								3
266.8 & 397.5 &	4,676,650	14,892,912	19,569,562					4
636 & 795 & 3/0								5
	4,676,650	14,892,912	19,569,562					6
								7
								8
								9
								10
	20,468,556	137,820,694	158,289,250					11
	20,468,556	137,820,694	158,289,250					12
								13
								14
								15
								16
								17
	571,508	3,768,091	4,339,599					18
	571,508	3,768,091	4,339,599					19
				868,069	14,316,261		15,184,330	20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	140,176,763	863,774,892	1,003,951,655	868,069	14,316,261		15,184,330	36

Name of Respondent Duke Energy Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2004	Year/Period of Report End of 2004/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	OH Construction: New Lines						
2	Eastfield Retail Tap		0.40	Pole	13.00	1	
3	Friendship Retail Tap		0.05	Pole	40.00	2	
4	Island Ford Retail Tap		0.06	Pole	33.00	1	
5	Rozzelles Retail Tap		0.08	Pole	38.00	1	
6	South Hickory Retail Tap		2.80		10.00	2	
7	Eastatoe Retail Tap		1.63	Pole	12.00	1	
8	Holcombe Road Retail Tap		0.05	Pole	20.00	1	
9	Perry Tap	Holcombe Road Retail Tap	4.28		11.00	2	
10	Hildebran Junct.(Pons Line)	Icard Retail Tap	0.01	H-Frame	40.00	1	
11	Sterlite Tap		0.11	H-Frame	40.00	1	
12							
13							
14							
15							
16							
17							
18							
19							
20	OH Construction: Major						
21	Rebuild						
22	Belton Tie	Toxaway Tie	4.15		21.00	2	
23	Newberry Main	Whitmire Retail Tap	7.30		8.00	2	
24	Tiger Tie	East Greenville Tie	5.23		21.00	2	
25	Spurrier	Huntersville	2.69	Pole	11.00	1	
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		28.84		318.00	20	

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	LINE COST Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	Line No.
									1
556.5	ACSR		100	71,647	213,849	131,069		416,565	2
954.0	AAC		100	9,121	495,313	303,579		808,013	3
556.5	ACSR		100	9,494	56,827	34,829		101,150	4
556.5	ACSR		100	27,545	18,905	11,587		58,037	5
556.5	ACSR		100	55,596	1,210,548	741,949		2,008,093	6
556.5	ACSR		100	36,861	493,247	302,313		832,421	7
556.5	ACSR		100		40,859	25,043		65,902	8
954.0	AAC		100	1,120,957	2,092,509	1,282,506		4,495,972	9
556.5	ACSR		44	6,146	17,702	10,850		34,698	10
556.5	ACSR		44		37,900	23,229		61,129	11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
954.0	AAC		100		1,216,729	745,737		1,962,466	22
556.5	ACSR		100		2,666,003	1,634,002		4,300,005	23
954.0	AAC		100		2,643,612	1,620,278		4,263,890	24
556.5	ACSR		44		320,426	144,342		464,768	25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				1,337,367	11,524,429	7,011,313		19,873,109	44

APPENDIX M: OTHER INFORMATION (ECONOMIC DEVELOPMENT)

Customers Served Under Economic Development:

In the NCUC Order dated Nov. 15, 2002, in Docket No. E-100, Sub 97, the NCUC ordered North Carolina utilities to review the combined effects of existing economic development rates within the approved Annual Planning process and file the results in its short-term action plan. The incremental load (demand) for which customers are receiving credits under economic development rates and/or self-generation deferral rates (Rider EC), as well as economic redevelopment rates (Rider ER) as of October 1, 2005, is:

Rider EC:

20 MW for North Carolina
22 MW for South Carolina

Rider ER:

0 MW for North Carolina
3 MW for South Carolina

APPENDIX N: LEGISLATIVE AND REGULATORY ISSUES

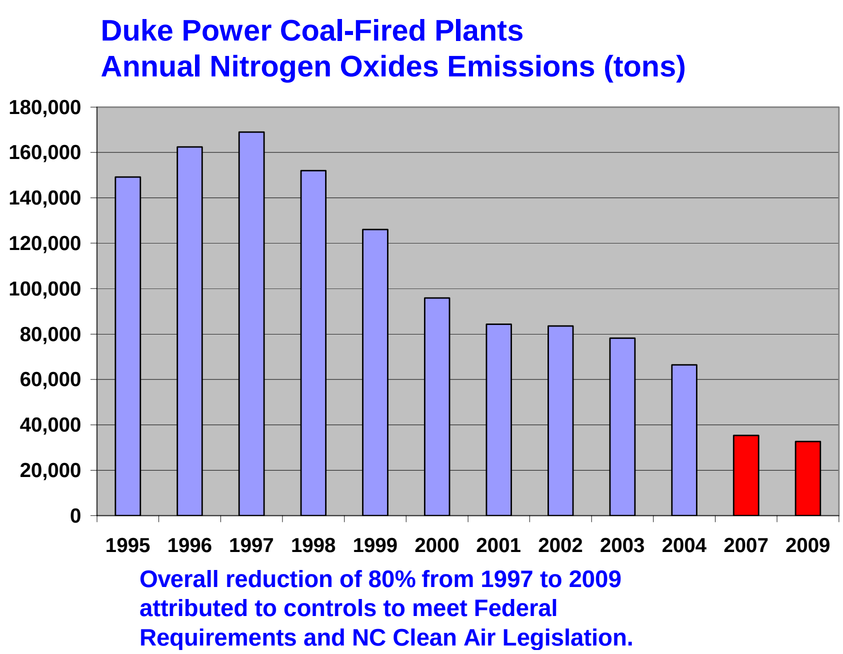
Duke Power is subject to the jurisdiction of federal agencies including the Federal Energy Regulatory Commissions (FERC), EPA and the Nuclear Regulatory Commission (NRC), as well as state commissions and agencies. In addition, state and federal policy actions have potential impact on the Company. This section provides a high-level description of several issues Duke Power is actively monitoring or engaged in that could have an impact on new generation decisions.

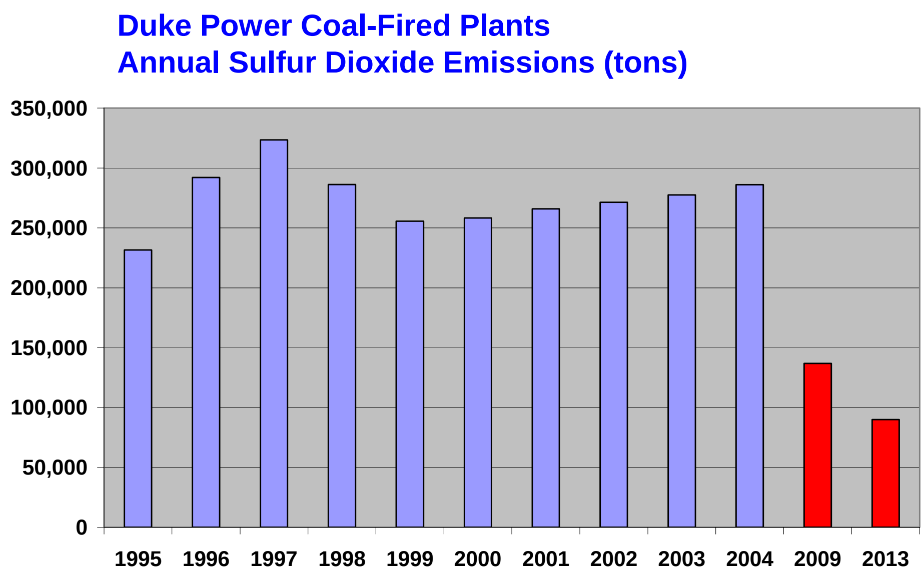
Air Quality

Duke Power is required to comply with federal regulations such as the Clean Air Act's Nitrogen Oxide (NOx) State Implementation Plan (SIP) Call and the 2002 North Carolina Clean Smokestacks Act.

As a result of the North Carolina Clean Smokestacks Act, Duke Power will reduce sulfur dioxide (SO_2) emissions by about 70 percent by 2013 from 2000 levels. The law also calls for additional reductions in NOx emissions by 2007 and 2009, beyond those required by the federal NOx SIP Call. This landmark legislation, which was passed by the North Carolina General Assembly in June 2002, calls for some of the lowest state-mandated emission requirements in the nation, and was passed with Duke Power's input and support.

The following graphs show Duke Power's NOx and SO_2 emissions reductions to comply with the federal NOx SIP Call and the 2002 North Carolina Clean Smokestacks Act.





70 % Reduction from 2000 to 2013 attributed to scrubbers installed to meet NC Clean Air Legislation.

These charts do not show additional reductions that are necessary to comply with the federal Clean Air Interstate Rule.

Duke Power must also comply with two new federal rules to reduce air emissions: the *Clean Air Interstate Rule* and the *Clean Air Mercury Rule***.**

Clean Air Interstate Rule (CAIR)

In May 2005, the EPA issued a Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (CAIR), which affects 28 states including North Carolina and South Carolina. The rule requires affected states to reduce emissions of SO_2 and/or NOx. The emissions controls that Duke Power is installing to comply with the North Carolina Clean Smokestacks Act will contribute significantly to achieving compliance with the CAIR requirements. Both North Carolina and South Carolina have taken steps to initiate the rulemaking process to implement CAIR.

Federal Clean Air Mercury Rule (CAMR)

In May 2005, the EPA published the Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, also referred to as CAMR. The rule establishes mercury emission-rate limits for new coal-fired steam generating units, as defined in Clean Air Act section 111(d). It also establishes a nationwide mercury cap-and-trade program covering existing and new coal-fired power units. Both North Carolina and South Carolina have taken steps to initiate the rulemaking process to develop these plans.

The federal CAIR and CAMR rules were released concurrently because the emission controls that will be required under CAIR to reduce NOx and SO_2 also reduce mercury emissions. The controls that Duke Power is installing to comply with the North Carolina Clean Smokestacks Act will contribute significantly to achieving compliance with CAMR. However, both CAIR and CAMR may result in additional controls and/or costs for the Company beyond those required to meet the North Carolina Clean Smokestacks Act.

Global Climate Change

Duke Energy views climate change, particularly potential policy responses to the issue, as a significant strategic business issue. Current U.S. policy includes a goal to reduce the greenhouse gas emissions intensity of the economy through voluntary measures. However, concern that greenhouse gas emissions from human activities may be influencing changes in the earth's climate system has resulted in a variety of local, state and regional responses, as well as increased policy debate at the federal level.

Duke Energy believes that a federal policy response is preferable to a patchwork of different state requirements, because it would be less costly to society and more effective in managing greenhouse gas emissions. In addition, the Company believes that the best course of action going forward is U.S. federal legislation that will result in a gradual transition to a lower-carbon-intensive economy, such as applying a federal-level carbon tax to all sectors of the economy.

Energy Policy Act of 2005

The Energy Policy Act of 2005 encourages investment in energy infrastructure, confers upon FERC a new role in policing transmission expansion, boosts electric reliability, and promotes a diverse mix of fuels to generate electricity. The Act increases protections for electricity consumers, encourages energy efficiency and conservation and repeals the Public Utility Holding Company Act (PUHCA).

There are several key issues that the Energy Policy Act can impact which are of importance to Duke Power. Some of those issues are:

- Reliability – The Energy Policy Act establishes an electric reliability organization, governed by an independent board, with FERC oversight.
- PUHCA and Merger Review – Repeals PUHCA transferring consumer protections to FERC and the states.
- Transmission Siting and Incentive Pricing – Encourages energy infrastructure investment, FERC backstop siting authority, and DOE identified "national interest electric transmission corridor" to be used by FERC, as a starting point, to address bottlenecks in the national grid.
- Native Load Protection – Assures firm transmission rights for serving native load.
- Economic Dispatch – DOE to study and report on the benefits of economic dispatch annually.

- Participant Funding – Provides that FERC "may approve" participant funding plan if the plan is not unduly discriminatory or preferential with the result being just and reasonable rates.

Duke Power will closely monitor the implementation of the Energy Policy Act at the state and federal levels.

Hydroelectric Relicensing

On March 28, 2002, the FERC issued an Order Approving a Subsequent License to Duke Power for the Queens Creek Hydroelectric Project, FERC Project No. 2694. Over the next several years, Duke Power will be pursuing FERC license renewal approval for seven hydroelectric projects and will surrender one license.

During 2003, Duke Power filed applications to renew licenses for:

- Bryson
- Dillsboro
- Franklin
- Mission

In 2004, Duke Power filed applications to renew licenses for:

- East Fork Project (Cedar Cliff, Bear Creek, and Tennessee Creek)
- West Fork Project (Thorpe and Tuckasegee)
- Nantahala Project (Nantahala, Dicks Creek, and White Oak)

In May 2004, Duke Power filed an application to surrender the license for its Dillsboro Project, a result of binding settlement agreements with stakeholders related to the relicensing of the East Fork, West Fork, and Nantahala Projects. Those settlement agreements were filed with FERC in January 2004 and call for the removal of the Dillsboro Dam.

On August 12, 2005, FERC issued annual licenses for the Bryson, Franklin and Mission projects, authorizing continued operation under the terms of the previous licenses until July 31, 2006. If FERC has not acted to issue a new license for any of those projects by that date, it will issue another annual license for that project.

Duke Power filed a Notice of Intent to File an Application for a New License for the Catawba/Wateree Project No. 2232 in 2003, five years prior to expiration of the license. The Catawba-Wateree Project includes the following developments:

- Bridgewater
- Rhodhiss
- Oxford

- Lookout Shoals
- Cowans Ford
- Mountain Island
- Wylie
- Fishing Creek
- Great Falls
- Dearborn
- Rocky Creek
- Cedar Creek and
- Wateree.

Duke Power is currently working with numerous stakeholders in an effort to enter into a binding agreement.

The duration of a new FERC license for a hydropower facility can range from 30 to 50 years depending on various factors at the time of relicensing. FERC's normal time frame to issue new licenses is 24 to 36 months after submittal.

Generating Units with Plans for Life Extension

STATION	NOTICE OF INTENT TO RELICENSE FILED	PRESENT LICENSE EXPIRATION DATE
Bryson Project No. 2601	1/27/2000	7/31/2006
Dillsboro Project No. 2602	1/19/2000	7/31/2006
Franklin Project No. 2603	1/27/2000	7/31/2006
Mission Project No. 2619	2/15/2000	7/31/2006
East Fork Project No. 2698	7/25/2000	1/31/2006
West Fork Project No. 2686	7/28/2000	1/31/2006
Nantahala Project No. 2692	8/7/2000	2/28/2006
Catawba/Wateree Project No. 2232	7/21/2003	9/1/2008

North Carolina Transmission Planning Process

Since May 2004, Duke Power has been working to develop a collaborative transmission planning process with North Carolina's major electric load-serving entities (LSEs). This effort has resulted in an agreement on a long-term comprehensive transmission planning process for North Carolina, facilitated by an independent third party, Gestalt, LLC, with input from other market participants. The process is designed to preserve reliability as well as enhance access by LSEs to a variety of generation resources.

Independent Transmission Coordinator Plan

On July 22, 2005, Duke Power filed a plan with FERC for the independent and transparent operation of the Company's transmission system.

The filing is a result of a year-long process of input and refinement, based on feedback received from various stakeholders. In proposed amendments to its Open Access Transmission Tariff (OATT), Duke Power is seeking FERC approval to establish both an Independent Entity to serve as its transmission coordinator and an Independent Monitor to provide additional transparency and fair system administration. The Company is seeking FERC approval of the plan by early 2006.

Under the proposal, the Independent Entity will be charged with performing key transmission functions under Duke Power's OATT. Duke Power will remain owner and operator of its transmission system, maintaining ultimate responsibility for providing transmission service. Duke Power has retained the Midwest Independent System Operator (Midwest ISO) to perform the role of Independent Entity.

While Duke Power is not joining the Midwest ISO, as Independent Entity the Midwest ISO is expected to perform a number of transmission functions, including:

- Evaluation and approval of all transmission service requests
- Calculation of Total Transfer Capability and Available Transfer Capability
- Operation and administration of the Duke Power Open-Access Same Time Information System (OASIS)
- Evaluation, processing and approval of all generation interconnection requests and performance of related interconnection studies, and
- Coordination of transmission planning.

The Independent Monitor will serve as an autonomous monitor of Duke Power's transmission system, providing a measure of neutrality in the Duke Power control area. The Independent Monitor will regularly perform a number of screens and other analyses related to the system, submitting quarterly reports to both FERC and regulatory commissions in North Carolina and South Carolina. Potomac Economics Ltd. has agreed to serve as Duke Power's Independent Monitor.

After two years of operation, Duke Power and the Independent Entity will convene a stakeholder conference to receive input and comments regarding whether the Independent Entity and Independent Monitor have measurably improved transmission service.